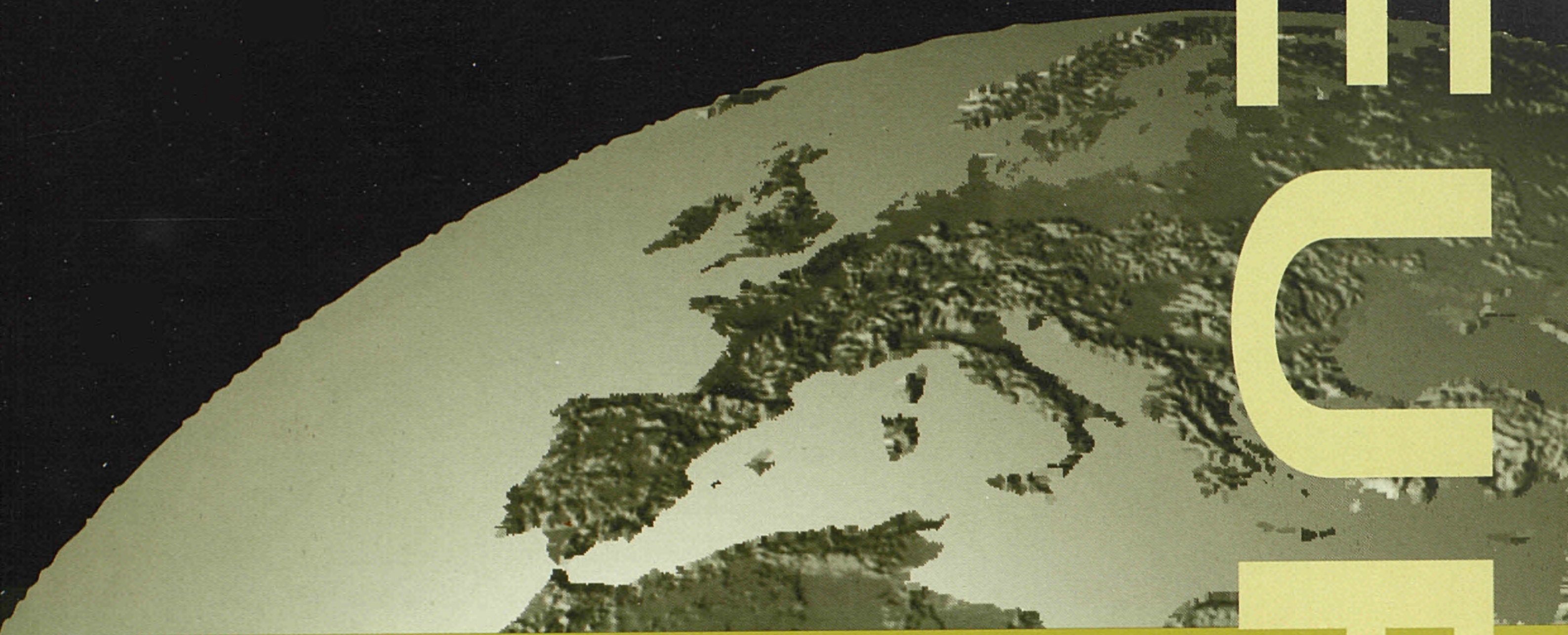
The Single Market Review

EUROPE



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Volume 10:

Single energy market

The Single Market Review

IMPACT ON SERVICES

SINGLE ENERGY MARKET

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The Single Market Review

IMPACT ON SERVICES

SINGLE ENERGY MARKET

The Single Market Review

SUBSERIES II: VOLUME 10

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This report is part of a series of 39 studies commissioned from independent consultants in the context of a major review of the single market. The 1997 Single Market Review responds to a 1992 Council of Ministers Resolution calling on the European Commission to present an overall analysis of the effectiveness of measures taken in creating the single market. This review, which assesses the progress made in implementing the Single Market Programme, was coordinated by the Directorate-General 'Internal Market and Financial Services' (DG XV) and the Directorate-General 'Economic and Financial Affairs' (DG II) of the European Commission.

This document was prepared for the European Commission

by

London Economics

It does not, however, express the Commission's official views. Whilst every reasonable effort has been made to provide accurate information in regard to the subject matter covered, the Consultants are not responsible for any remaining errors. All recommendations are made by the Consultants for the purpose of discussion. Neither the Commission nor the Consultants accept liability for the consequences of actions taken on the basis of the information contained herein.

The European Commission would like to express thanks to the external experts and representatives of firms and industry bodies for their contribution to the 1997 Single Market Review, and to this report in particular.

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List of abbreviations

bbl	barrel
bcm	billion cubic metres
CCGT	combined cycle gas turbine
CEGB	Central Electricity Generating Board
CHP	combined heat and power
CPI	consumer prices index
DSM	demand side management
EC	European Community
ECU	European currency unit
EEC	European Economic Community
EIREM	model of European electricity system
EU	European Union
EU-12	Belgium, Denmark, Germany, Greece, Spain, France, Ireland, Italy, Luxembourg, Netherlands, Portugal, United Kingdom
EU-15	Belgium, Denmark, Germany, Greece, Spain, France, Ireland, Italy, Luxembourg, Netherlands, Austria, Finland, Sweden, Portugal, United Kingdom
Eurostat	Statistical Office of the European Communities
EWI	Energie Wirtschaftliches Institut (Köln)
FGD	flue gas desulphurization
FSU	former Soviet Union
GDP	gross domestic product
GJ	gigajoule
GME	Gasducto Maghreb Europe
GW	gigawatt
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IPP	independent power producers
kcal	kilocalorie
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
LCPD	Large Combustion Plant Directive
LE	London Economics
LNG	liquefied natural gas
LOLP	loss of load probability
LSFO	low sulphur fuel oil
MIDAS	model of European electricity system
MMBtu	million British thermal units
mtoe	million tonne oil equivalent
mWh	megawatt hour
n/a	not available
NAFTA	North American Free Trade Agreement
NCV	net calorific value
nTPA	negotiated third party access
NTUA	National Technical University of Athens
OCGT	open cycle gas turbine
OECD	Organization for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
p.a.	per annum
r/p	reserve to production ratio
RPI-x	Retail Price Index-x
SB	single buyer
SBM	single buyer model
TEN	Trans-European Network (energy)
toe	tonne oil equivalent
TPA	third party access
TWh	terawatt hour
UKCS	United Kingdom continental shelf
USC	ultra super critical
VAT	value added tax

1. Summary

This report assesses the economic consequences of completing the single energy market. It is one of a group of studies being undertaken on behalf of the European Commission to assess the effects of completing the European Union's single market. The study examines potential changes to costs, prices and trade flows in the electricity and natural gas industries. In many respects, the single market in energy is incomplete, and this study looks at measures yet to be taken. In this it differs from the studies of most sectors, which review the effects of previous changes.

Electricity and gas are transported by networks that are essentially 'natural monopolies', because it will never be economic to build competing networks to serve the same customers. This tendency towards monopoly has been furthered in some cases by exclusive jurisdictions, which restrict rights to build competing infrastructure even where it is economic to do so, as is sometimes the case for large long-distance transmission lines. Exclusive state ownership and vertical integration have further limited the extent of competition even where, as in the case of electricity generation, an activity is not naturally monopolistic.

The lack of competition in electricity and gas has permitted wide divergences of price in neighbouring markets. It has also enabled national policy goals to be pursued, leading to divergences in the mix of fuels and plant type used in electricity generation, and variations in the market share of gas, that appear larger than would result from differing economic circumstances alone.

These differences have raised concerns at two levels. At the national level, there have been concerns that prices may be unnecessarily high, damaging national competitiveness and leading to a loss of consumer welfare. At the European Union (EU) level, there has been concern that present practices, in effect, create internal frontiers and restrict the free movement of goods and services that is central to the completion of the single market. This study does not seek to address those issues which are a matter of national policy alone, but does consider those issues which affect trade, and the ability of consumers to choose their source of supply freely from within the EU.

In practice, most of the discussion of liberalization centres on providing non-discriminatory access to the natural monopoly networks (i.e. third party access, TPA). TPA has formed the core of the Commission's draft directives on liberalization. The removal of exclusive rights to build and operate transport infrastructure and generating plant is also an important aspect of liberalization as, in some respects, is unbundling of functions. The work presented in this report was mainly completed before apparent agreement on the proposed Electricity Directive in June 1996. Consequently, the final proposed Directive is not explicitly considered, but the study is consistent in broad terms with the agreed text.

1.1. The approach

This study assesses the effect of liberalization at the EU level by comparing three scenarios for the future evolution of each industry. A continuation of the present industry structure is taken as a base against which other scenarios can be measured. An open market scenario (including full compulsory TPA, unbundling, and the removal of exclusivity rights) is assessed to identify the potential benefits of competition. An intermediate competition scenario, including negotiated TPA, is used to analyse the effects of partial reform, which is more likely than full competition in the near future and is close to the measures agreed at the Council of Ministers meeting at the end of June 1996. The scenarios are examined by modelling rather than analogy with other liberalized markets. This is because the circumstances of the European energy industries are different from those of other markets, especially for the gas industry, and liberalization internationally remains uncommon and recent, so experience on which to base comparisons is limited. Two well established models of the European electricity system, EIREM and MIDAS, have been used to model the electricity industry. A conceptual model developed for this study has been used to analyse the gas industry.

1.2. Electricity results

There are several potential sources of gains from liberalizing the electricity industry. Potential gains from trade include the siting and use of least cost plant across borders, the facilitation of trade with Eastern Europe, and the ability to exploit differences in the timing of demand peaks. Also, the margin of surplus capacity in each country required to cope with unusual demand peaks and plant outages may be reduced as increased interconnection between systems provides additional resilience. Cost savings from increased efficiency, resulting from increased competition, will potentially be realized in the form of lower construction and operating costs, and the choice of which type of fuel the plant will burn on economic rather than policy grounds. The total cost of generation in the EU is greater than ECU 100 billion p.a. Savings, therefore, tend to be large in absolute terms, even from modest percentage gains.

The estimates in this study show savings of ECU 10–12 billion p.a. in the open market scenario, with savings of approximately ECU 4–6 billion p.a. in the intermediate competition scenario. There are corresponding price falls of ECU 2–4/MWh, with consequent benefits to the competitiveness of Community industry. This is equivalent to a price reduction of 5–11% for large industrial consumers, and 2–4% for residential consumers, although in practice residential consumers may not experience all of these gains as some may be appropriated by local distribution companies. The majority of the savings arise from lower construction and operating costs for generating plant, and the less frequent choice of higher cost plant type on policy grounds. In view of the cost of generation, and the present cost and price differences across the EU, these estimates appear conservative and greater savings may be achievable in practice. The savings greatly outweigh the potential increase in costs from any additional regulation.

Trade is expected to increase in the short term, requiring new transmission links, including links specified in the Commission's TENs programme, although trade reduces from its maximum level in the longer term as costs converge. Liberalization is also likely to lead to an increase in the use of gas in generation, with corresponding environmental benefits from reduced emissions of CO_2.

Such savings indicate that it is desirable to introduce TPA for as wide a range of consumers as possible, including large industrial consumers and distribution companies. Mechanisms for non-discriminatory construction and despatch of plant, including unbundling of generation and transmission, are also required to achieve maximum savings. Interconnection of networks is likely to increase, and abolition of exclusive rights to build new infrastructure, and other policy measures, should facilitate this.

Security of supply will remain a legitimate concern of policy because of the wider economic and social effects of supply disruption. In particular, increased use of gas for power generation is likely to lead to increased reliance on imports from Russia and Algeria. However, policies to promote security of supply can be compatible with liberalization. For example, if obligations are placed on distribution companies to ensure security of supply, this will lead them to contract appropriately with generators. Similarly, measures to encourage the installation of dual firing can be applied in a non-discriminatory fashion, making them similar in character to requirements to meet environmental standards. This need not impair the operation of a competitive market, and gains from liberalization can still be realized.

1.3. Gas results

The introduction of TPA in gas is likely to lead to some benefits for large consumers but not necessarily for small consumers. Liberalization in gas is more problematic than in electricity because most incremental supply to the EU is likely to come from one of three main sources outside the EU (Russia, Algeria and Norway) and in each case, exports from these countries are effectively under state control, and may remain so. This makes the introduction of true competition much more difficult. We have therefore examined two cases. The first includes very limited competition between producers. The second, more favourable, case includes significant price competition among producers.

If competition between producers is limited, monopoly economic rents may be present, because demand for gas is inelastic at prices below the cost of using a competing fuel, leading to the potential for prices to be raised to close to the ceiling imposed by competing fuels without a corresponding loss of volume. Rents are likely to be present in both the industrial and power sectors, and are especially large in the power sector.

The presence of oligopoly power in the upstream and rents in the value chain leads to questions over who will be able to appropriate the rents. At present, the majority of rents appear to accrue to producers, with some accruing to transmission companies. TPA is likely to lead to transmission companies losing rent to consumers and producers, and potentially to consumers gaining rent from producers. If consumers arc more effective bargainers than transmission companies, they will secure additional rents from producers, leading to price falls at the EU border. However, if they are less effective negotiators, then producers will appropriate some of the rent that presently accrues to transmission companies, with limited gains to consumers, and a rise in border prices.

Consideration of the influences on negotiations suggests that power companies and large industrial consumers are likely to be more effective negotiators than transmission companies, as they have stronger incentives to negotiate effectively. However, the position is less clear for distribution companies.

This leads to the conclusion that TPA for large consumers, including power plants, is likely to have advantages. Price reductions of 5–8% are expected to be achieved in the power sector, and 3% for large industrial consumers. This will lead to savings of some ECU 300–900 million p.a. with corresponding benefits for the competitiveness of EU industry. However, these gains are less clear for distribution companies and it is possible that no significant price reductions may be achieved by residential consumers.

If there is limited competition in production, delivery to the European border, and distribution (the major components of cost), the potential for productive efficiency gains is also limited.

The other scenario, in which there is significant price competition between producers under a TPA regime, has a very different outcome. Gains to consumers would be very large, as they would be able to appropriate rents and productive efficiency gains may also be present. There could be very large gains (several billions of ECU p.a.) if TPA were to lead to full gas-to-gas competition.

Removal of exclusivity rights for pipelines is likely to be advantageous, for example because it enables short independent pipelines for the power sector, and may increase the interconnectivity and operational effectiveness of the EU gas system. The construction of independent pipelines and the introduction of TPA may allow independent power projects to proceed which otherwise would not. This may increase consumption with corresponding environmental benefits to the extent that gas displaces other fuels. Otherwise effects on consumption will be limited. Any increases in consumption will be met from additional imports as there is very limited scope for increasing production within the EU in the longer term.

The problem of upstream oligopoly may be addressed by measures to increase the diversity of suppliers to the EU. The problem of rent flows may also potentially be addressed by policy measures, for example by fiscal measures (perhaps analogous to the transit fees often presently levied on gas pipelines). Simply retaining the existing concentration of buyer power in the transmission companies seems very unlikely to be the most effective route of counteracting upstream power from the point of view of the consumers or the EU as a whole, as it does not enable consumers to gain any of the rent appropriated from the upstream, which remains with the transmission companies.

The growth of demand from the power sector causes potential concern on security of supply, but interruptible contracts with electricity generators may have the effect of increasing security of supply for other sectors. Indeed, the potential growth of gas demand from the power sector is among the greatest challenges presently facing the European gas industry. Consequently, measures that encourage growth of gas demand, such as liberalization of the power sector, may have as great an effect on the gas industry as reform within the gas sector itself.

2. General introduction

The European Commission has asked a consortium led by London Economics[1] to report on the economic consequences of completing the single energy market. This report describes the study, the results obtained and the policy implications of the work. This study is one of several being undertaken on behalf of the Commission to assess the effects of completing the single market on various industries, in accordance with the mandate laid down in Council Resolution 92/1218. Unlike the studies of most other sectors, this study assesses the potential benefits from future measures, rather than assessing the effect of existing programmes. This is because measures for completing the single market in energy have yet to be introduced.

The work is directed at determining the effects of completing the single energy market by comparing projections based on the continuation of existing energy market structures with alternative scenarios that represent differing degrees of reform at the level of the EU. The focus is on the benefits and costs of market reform.

The principal indicators to be used to measure the effect of completing the single market are:

(a) energy consumption patterns;
(b) prices and costs for each stage of the value chain;
(c) levels of investment;
(d) changes in the pattern of inter-state trade;
(e) costs of production of the Community's energy system as a whole; and
(f) environmental effects.

The study covers the period to 2020.

The original terms of reference for the study indicated that the assignment has four interlinked phases:

(a) Defining alternative market frameworks required to create a single energy market and their regulatory and institutional characteristics. This is achieved by specifying scenarios and, in practice, centres around consideration of third party access (TPA) to transmission infrastructure, rights for the exclusive construction of infrastructure, and the completion of Trans-European Energy Networks (TENs).
(b) Evaluating the impact of these alternative frameworks on the structure of production, consumption, and trade. This is achieved largely by modelling, because the institutional and industry circumstances of the EU are unique. However in discussing the prospects for reform, reference is made to experience elsewhere.
(c) Assessing the impact of the alternative frameworks on the efficiency of the EU energy system compared with what it would be under a continuation of present arrangements. This is derived from a comparison of the results under the various scenarios.
(d) Identifying the key policy issues that emerge from the analysis for the successful completion of the single energy market and making recommendations as to how these may be addressed.

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1 The other members of the consortium are EWI (Energie Wirtschaftliches Institut|) based in Köln, NTUA based in Athens, and AUPEC based in Aberdeen.

This report describes each of these stages of the work. It has separate sections on electricity and gas, because the issues involved and the modelling approaches adopted are different for the two industries. Each section comprises the following:

A description of the industry environment. This section outlines the present situation in each industry, and the institutional framework in which it operates. The description is more detailed for gas than for electricity as the particular character of the market has a more direct and profound effect on the outcome of the modelling than is the case in electricity. This section also summarizes the industry data which is used as input for the models.

A description of the scenarios for the evolution of each industry. This section describes the industry structures that might arise from completing the single market and compares this with the present structure. For electricity, there is a separate section describing the likely sources of benefits and costs from liberalization.

A description of the modelling work. This describes how the scenarios have been realized in modelling terms.

Results. This section describes results of the modelling work. This includes calculation of the output measures identified above.

Discussion of results. A detailed assessment of the implications of the results, both qualitatively and quantitatively.

Policy implications. The key policy issues are discussed and the results are described. Recommendations regarding policy are made on the basis of this analysis.

This report considers reform at the level of the present EU as a whole. It does not seek to identify or assess the possibilities for alternative industry structures within countries, and does not consider issues of ownership. Each of these is important, and there is scope for a wide variety of structural reform within individual Member States. However, consideration of such issues is beyond the scope of this report except where they relate directly to the completion of the single market in energy.

2.1. Background to this report

The Single European Act defined a single market as 'an area without internal frontiers in which the free movement of goods, persons, services and capital is ensured'. As part of implementing the Single European Act the European Commission is attempting to create an 'Internal Energy Market'.[2] This has proved to be an extremely complex and controversial issue and the Commission's proposals have been widely resisted by some Member States.

For the first stage of the market the Council of Ministers have agreed:

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2 European Commission, *The Internal Energy Market*, Brussels, COM(88) 238, 2 May 1988.

(a) Greater transparency of prices charged to large customers.[3] The Commission now collects and publishes price statistics.
(b) Free competition among EC companies to sell equipment to energy undertakings.[4]
(c) Mandatory transit of power between authorized grid operators in Member States across intervening grids.[5]

In January 1992 the European Commission published its proposals for the subsequent stages towards the 'Completion of the internal market in electricity and gas'.[6] For the second stage of the integrated electricity market the Commission proposed:[7]

(a) Liberalizing line construction and providing a right of connection of new lines to existing transmission systems.
(b) Opening up electricity generation to competition.
(c) Freedom of purchase and third party access (TPA). This applied in electricity to customers buying more than 100 GWh p.a., and a hundred or so distribution companies selling more than 3% of the energy within a Member State (the access was to be subject to capacity being available). It also applied in gas to large industries or distribution companies.
(d) 'Unbundling', i.e. separation of the management (by splitting activities into separate divisions in integrated utilities) and of accounts between generation, transmission and distribution. The aim was to ensure transparency of operations.
(e) 'Harmonized, transparent and non-discriminatory procedures', which included fair terms for use of transmission and distribution systems.
(f) Reduction of governmental influence on electricity and gas industries and increased commercial freedom for undertakings, which the Commission regards as essential to allow undertakings to face competition on equal terms.
(g) Harmonization, which was interpreted to mean:
    (i) control of state aids and of discriminatory pricing in favour of large customers, and
    (ii) 'non-discriminatory procedures with which producers, suppliers and consumers who wish to buy and sell electricity on the interconnection network must comply'.

These proposals were then amended in December 1993[8] in the face of widespread opposition to try and achieve consensus. These amendments included:

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3 Council Directive of 29 June 1990 concerning a Community procedure to improve the transparency of gas and electricity prices charged to industrial end-users, 90/337/EEC, OJ L 185/16, 1992.

4 Council Directive of 17 September 1990 on the procurement procedures of entities operating in the water, energy transport and telecommunications sectors, 90/531/EEC, OJ L 297/1, 1990.

5 Council Directive of 29 October 1990 on the transit of electricity through transmission grids, 90/547/EEC OJ L 313/30, 1990.

6 European Commission, Completion of the internal market in electricity and gas, Brussels, 21 January 1992.

7 To cater for national security concerns the proposals also allowed for the protection of indigenous sources of electricity generation up to 20% of total requirement. There was also a provision for subsidizing schemes of less than 25 MW that are based on renewable sources of energy and waste.

(a) making third party access (TPA) to the network negotiated, rather than compulsory;
(b) permitting Member States a second option in introducing competition in electricity generation by permitting either licensing or calls to tender;
(c) restricting 'unbundling' to financial accounts, rather than operational management although maintaining the independence of system operation; and
(d) increasing the role and importance of public service.

The proposals reflected the view of the Council of Ministers, set out in November 1992, that more competitive, transparent and efficient gas and electricity markets are desirable, and that the internal market should comply with six principles:

(a) security of supply;
(b) environmental protection;
(c) protection of small consumers;
(d) transparency and non-discrimination;
(e) recognition of the differences between national systems; and
(f) transitional provisions.

In response to the revised proposals from the Commission, the French Government proposed a 'Single Buyer Model' (SBM) as a form of organization of the sector which it believed to be consistent with EC objectives of promoting competition and creating a single energy market. The SBM proposals are seen, by others, as being an attempt to protect the right of national governments to pursue their own industrial policies in the power sector (such as the development of nuclear power). The proposals were extensively discussed and were the subject of a report by the research institute EWI in early 1995.[9] In March 1995, the Commission published a Working Paper.[10] It concluded that the negotiated TPA (nTPA) and the Single Buyer (SB) systems were not economically equivalent and that the SB system falls short of what is desirable or achievable from a competition point of view. The paper goes on to say that the SBM, with its effective import monopoly, appears to run contrary to Article 30 of the Treaty of Rome, which prohibits such import restrictions. Maintaining exclusive rights over imports, transmission and distribution appears contrary to the principle of the free movement of goods and services.

The debate continued under a proposal from the Italian Presidency, under which the controversial issue of whether distributors were granted TPA rights would be at the discretion of Member States, at least initially, subject to a certain proportion of the market being opened up. At the time of finalizing this report (July 1996) it appears that agreement has been reached that Member States must open 22% of their markets to competition, rising to 33% by 2003. The threshold at which large consumers will have access will be successively lowered from 40 GWh p.a. (although this is not legally enforceable) to 9 GWh p.a. Progress will be

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8 European Commission COM(93) 643 final. Amended proposal for a European Parliament and Council Directive concerning common rules for the internal market in electricity (COD 384) and natural gas (COD 381).

9 TPA and single buyer systems: producers and parallel authorizations: small and very small systems. EWI (Energie Wirtschafliches Institut), Köln, March 1995.

10 SEC (95)464 final: working paper of the Commission on the organization of the Internal Electricity Market. Proposal for a European Parliament and Council Decision on guidelines for the Trans-European Energy Networks (Common Position (EC) No 12/95 of 29 June 1995, OJ C 216, 1995).

reviewed, with possible further liberalization after 2003. This agreement was reached too late for its details to be reflected in the analysis for this report, and the extent to which the measures will lead to a genuine opening of markets remains unclear. However, it appears broadly to correspond to the Intermediate Competition scenario described in this report.

The Commission has also been reviewing the completion of the Trans-European Energy Networks (TENs), which is an important objective of EU policy, and has recently issued an information document on the subject.[11] The completion of TENs is discussed in this report within the broader context of completion of the single market.

11 Community Guidelines and Projects of Common Interest, November 1995.

3. Part A: Electricity

3.1. Introduction

This part of the report describes the consequences of completing the single market for electricity. The characteristics of the industry are first briefly described, to provide a background to the scenarios. Present consumption patterns are outlined, and the future underlying growth of demand is forecast. Included in this is a description of the present pattern of trade. The costs of different types of generating plants are then described. The commercial structure of the industry is also briefly reviewed to highlight the principal drivers behind the introduction of TPA.

The remainder of this part of the report is divided into the following chapters:

Chapter 4. *Industry characteristics:* describes demand, supply, trade flows and the commercial structure of the industry.

Chapter 5. *Scenarios:* describes the scenarios for the future evolution of the electricity industry. The scenarios are:

(a) *Present trends:* a continuation of present industry structures.

(b *Negotiated Third Party Access (nTPA):* negotiated access to the transmission system by independent producers and industrial consumers, and perhaps by distribution companies, is discussed. The extent to which a single buyer model (SBM) might have the same effect is also considered.

(c) *Third Party Access (TPA):* full competition with open buying and selling of electricity, including compulsory access to networks for independent power producers (IPPs) and large consumers. The right of access is also assumed to be extended to distribution companies. The right of independent parties to invest in transmission and distribution infrastructure, and unbundling of functions, are also included as part of this scenario.

This chapter includes a review of the sources of liberalization, and the potential gains and costs including preliminary quantifications of the order of magnitude of likely gains.

Chapter 6. *Modelling of scenarios*: a description of the use of models to examine the scenarios.

Chapter 7. *Results of modelling*: the effect of each scenario on key economic variables (consumption, costs and trade flows).

Chapter 8. *Conclusion and policy implications*: the policy implications of the results are described.

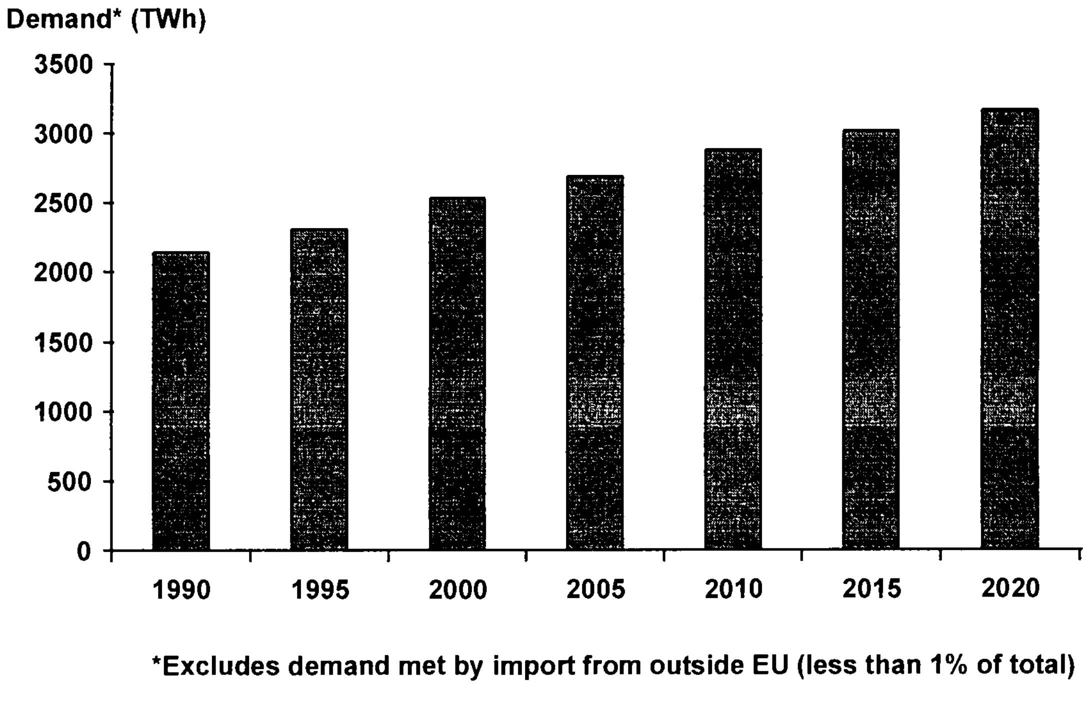
4. Industry characteristics

4.1. Demand

Electricity demand growth rates have usually been forecast on the basis of forecasts of GDP growth. The overall level of activity in an economy, as measured by GDP, has been taken as the principal driver of demand, because electricity is not highly price elastic, and pricing regimes have been relatively stable. In the past, demand often grew at about the same rate as GDP, or even more rapidly. However, more recently there has been evidence that increasing efficiency of electricity use and saturation in some markets, especially the residential sector, has led to growth rates for electricity demand below those for GDP. This trend is expected to continue.

The base case electricity demand used in this study is taken from the Conventional Wisdom Scenario in the 'Energy Futures to 2020' study carried out for the Commission using the MIDAS model, which includes both economic growth and price as drivers of demand. This shows demand growing at 1.7% p.a. in the period 1990 to 2000, and at 1.2% p.a. thereafter. This corresponds to a GDP growth rate of 2.1% p.a. throughout the period. Prices are forecast to remain static in real terms or fall slightly but further moderate price falls would not have a large effect on demand. The forecasts are shown in Figure 4.1. Demand varies slightly from this base level in the various scenarios. A breakdown of consumption by sector is shown in Table 4.1. This shows industrial electricity use accounting for some 40% of consumption, residential use a further 30%, with the remainder commercial and other use.

Figure 4.1. Electricity demand in the EU



Source: Energy futures to 2020.

Table 4.1. Electricity demand by sector (EU-12, 1993)

Sector	Million toe	% of consumption	TWh
Industry	68.7	42	799
Residential	49.0	30	570
Commercial	37.5	23	436
Other	7.8	5	91
Consumption	163.0	100	1896
Own use and losses	29.0	N/A	337
Total production and imports	192.0	N/A	2232

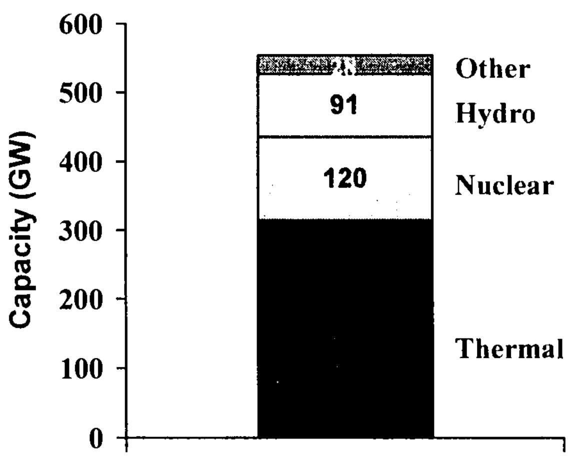
1 toe = 10^7 kcal NCV
1 million toe = 11.63 TWh
Source: IEA, EU-12 refers to the then 12 Member States of the EU.

4.2. Supply

4.2.1. Capacity

There are presently some 550 GW of generating capacity in the EU. Figure 4.2 shows this divided by main plant type. The majority of this is thermal generating capacity, although nuclear and hydro are both significant.

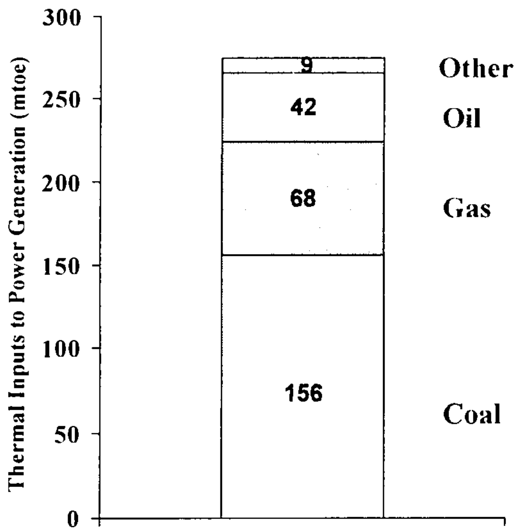
Figure 4.2. Generating capacity in the EU (1995)



Source: Energy Futures to 2020.

Figure 4.3 shows generation from thermal power plants by fuel type. Coal is the main source of thermal generation, accounting for just over half the total. Oil use is also significant, especially in Italy, and gas consumption is increasing rapidly, especially in the UK.

Figure 4.3. Fuel use in thermal power generation (1995)



Source: Energy Futures to 2020.

4.2.2. Costs

The capital costs of generation from various technologies shown in Figure 4.4 are taken from the assumptions used in the 'Energy Futures' study (*Energy Scenarios to 2020 for the European Union*, Report to the European Commission, DG XVII/A2 by NTUA and ESAP, October 1995). OCGT has the lowest capital cost, but high fuel costs mean that it is used as peaking plant. CCGT has a low capital cost and high thermal efficiency, which often makes it an attractive choice for new plant. Coal plant (including IGCC in the longer term) remains a frequent plant choice, but nuclear plant tends to be ruled out by high costs and political difficulties (except in France). Projections of these through time are shown in the Appendices. Costs are assumed to differ between countries, as shown in Table 4.2 the most significant variation is the lower cost of nuclear power in France. These differences are assumed to decline by 70% by 2005 and 90% by 2010 under full compulsory TPA. Under nTPA the corresponding rates are 50% and 70%.

The cost data is based on the inputs for the 'Energy Futures to 2020' study, to maintain consistency with the Commission's other work in the energy sector. Comparison with London Economics' data shows that lower costs may be achievable. In particular the price of gas fuelled CCGT relative to other plant may be lower than shown. However, this would only serve to further the already very strong position of gas in the market, and so reinforce the conclusions derived.

Fuel costs at the European border are treated as an exogenous variable for modelling purposes. The assumptions are in line with the conventional wisdom scenario in the Energy Futures study and are shown in Figure 4.5. Coal prices rise very slightly; oil and gas prices rise more strongly.

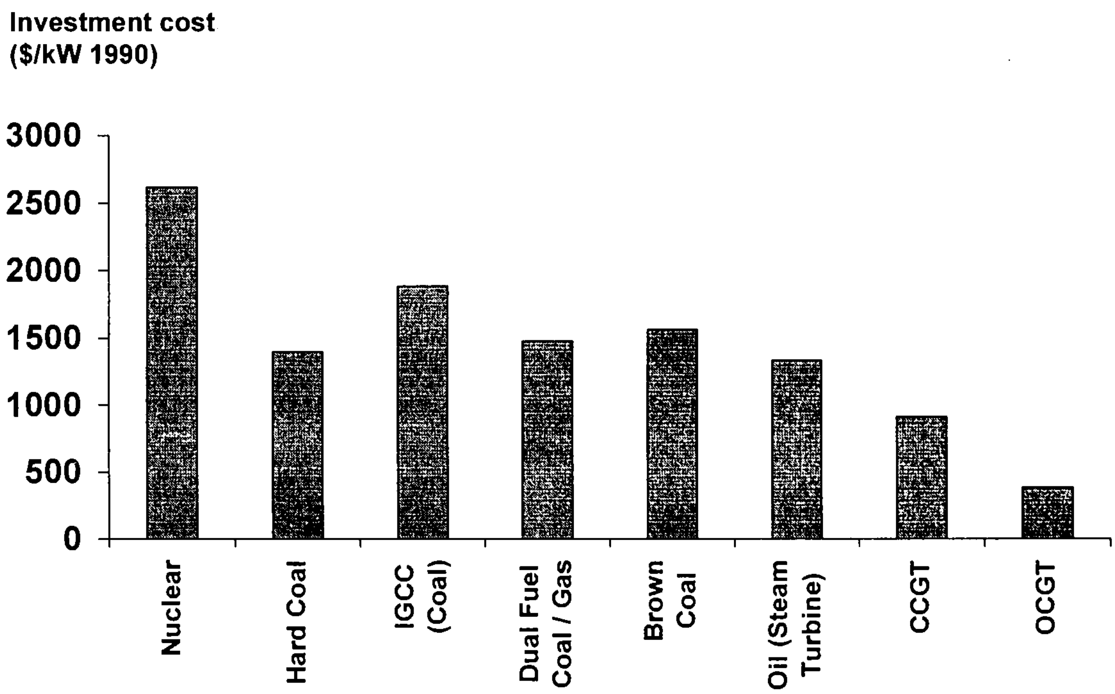
Table 4.2. Variations relative to baseline of generating costs at present[1]

Plant Type	Country	Variation (%)
Nuclear	Germany France Belgium Spain/Portugal	+ 15 - 12 - 6 + 6
Coal	Spain/Portugal	+ 5%

Source: modelling assumptions

[1] Baseline assumptions are from the Energy Futures to 2020 study and are shown in Figure 4.4.

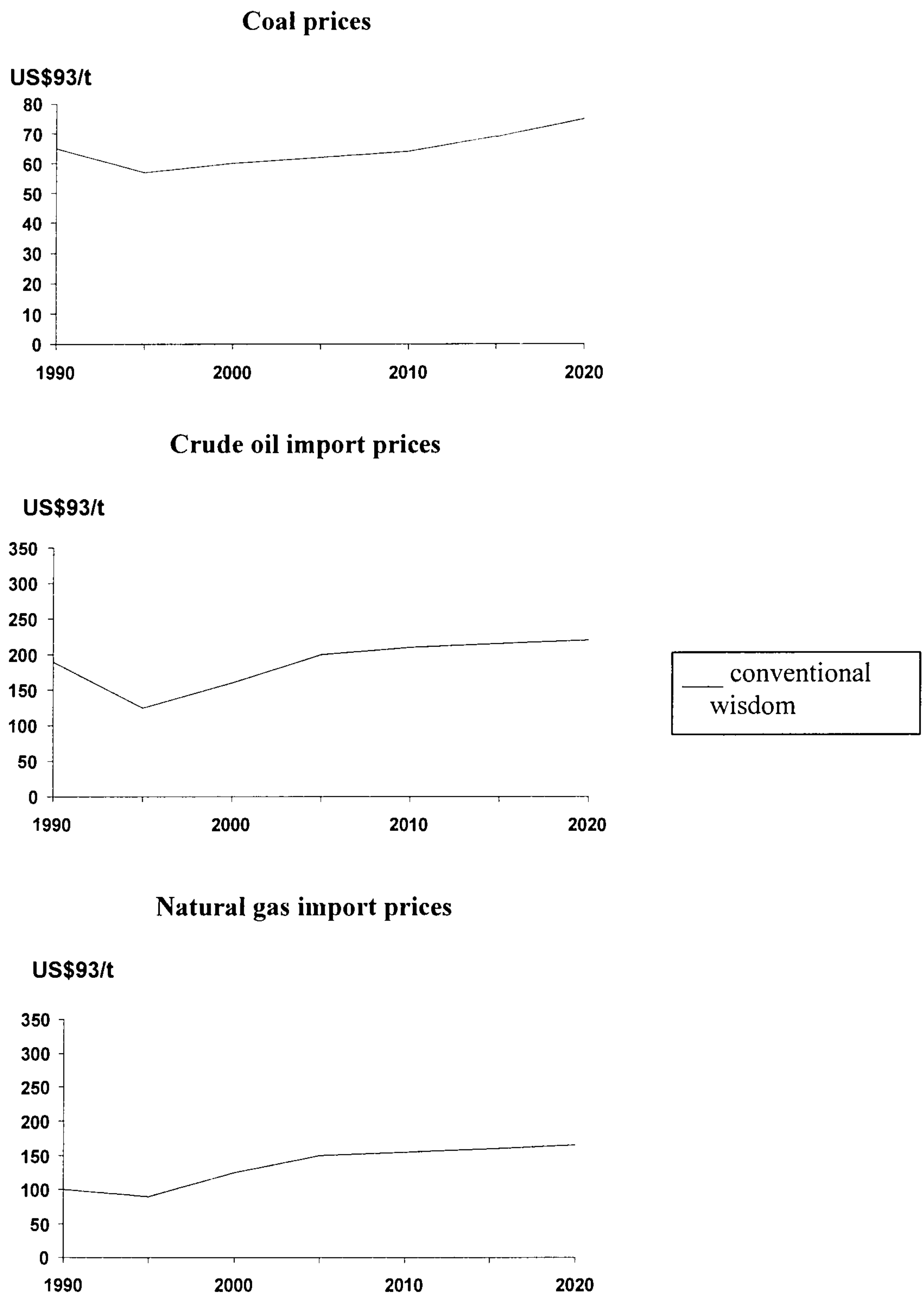
Figure 4.4. Comparison of capital costs of various type of plant



Note: OCGT= Open Cycle Gas Turbine
CCGT = Combined Cycle Gas Turbine
IGCC - Integrated Gasification Combined Cycle

Source: Energy Futures to 2020.

Figure 4.5. Fuel import price projections



Source: Energy Futures to 2020.

A sensitivity to the assumption on gas prices is examined in the light of the resource costs shown in the section of this report dealing with gas. These resource costs imply that potentially very large quantities of gas are available for delivery to the European border for costs in the range of US$ 2.70–3.50/ MMBtu. In the high gas price scenario, the price of gas for baseload is assumed to remain close to US$ 3.50/MMBtu (approximately US$ 140/toe) which leads to a very large rise in the amount of gas to the power sector.

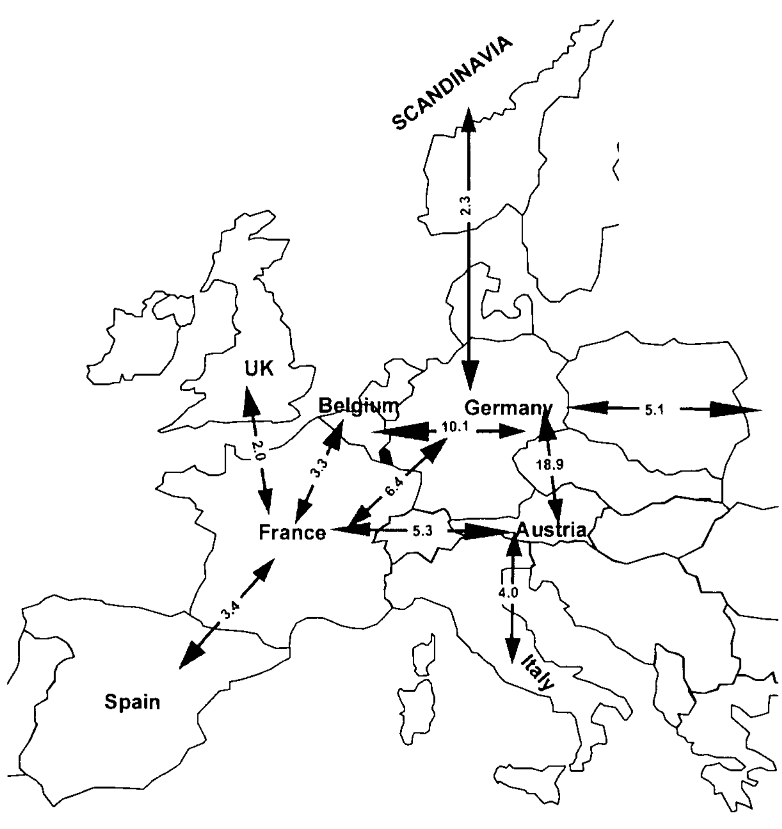
A coal price constant in real terms appears a plausible scenario in view of the nature of the reserve base. However, the key determinant of the fuel mix is the relative, rather than absolute, price of fuel, and here the major issue is whether gas will retain its present very strong competitive position. This is addressed by the contrasting low and high gas price scenarios.

A carbon tax is not treated explicitly in the base scenarios, although it remains a possibility. It has the effect of further improving the competitive position of gas in generation, because gas emits the least CO_2 per unit of energy produced. This would tend to reinforce the trends shown in the low gas price case. A carbon tax also favours nuclear power on economic grounds, although this is assumed to stay unacceptable on policy grounds in most of the EU.

4.3. Existing trade flows

There are presently large flows of electricity within the EU. The map in Figure 4.6 shows export capacities of main trade links in GW. The largest flows are exports from France and the capacity of the links reflects this, with links from France to other consuming regions. Present trade flows are illustrated in Section 7 (Figure 7.3) and compared with forecasts.

Figure 4.6. Present export capacities in GW



Source: EWI

4.4. Industry structure

4.4.1. Activities carried out within the electricity industry

The production and delivery of electricity to the consumer comprises several activities:

(a) generation of electricity in a power plant;
(b) transmission of electricity at high voltage to distribution companies and large industrial consumers;
(c) distribution of electricity at low voltage to the final consumer.

In liberalized environments with access to the networks, there is the separate commercial activity, referred to as the supply or merchant function. This involves buying bulk power from the generator, buying transmission and distribution services, and collecting payment from the consumer. It is a trading function and, in principle, distinct from the physical activities of generation, transmission and distribution. However, at present, supply is integrated with transport activities in continental Europe (but not in the UK).

4.4.2. Special characteristics of the electricity industry

Electricity has two characteristics that make it distinct from other commodities:

(a) it is effectively impossible to store (except in limited quantities in expensive pumped hydro plants);
(b) power is supplied over a network, which makes it impossible to unambiguously assign an individual customer's consumption to production from a specific generating plant.

In addition, there is the natural monopoly character of the network, which electricity has in common with other activities (gas, water and, to some extent, telecommunications) where the economies of scale and scope are so large that it is uneconomic to build competing networks. It is this natural monopoly characteristic that creates the need for TPA to networks as a key element of introducing competition to electricity markets.

4.4.3. Present structure in Europe

At present generation and transmission are vertically integrated in most of Europe, being carried out by a single utility (as in Italy) or a group of utilities (as in Germany). There is also often a monopoly of imports. Distribution is typically carried out by local distribution companies, often with some form of municipal involvement. Distribution is also controlled by the generator in some countries, making the entire chain vertically integrated. In some cases the degree of vertical integration is moderated, for example in Spain, Denmark and the Netherlands. In the UK, there is effective separation of generation and transmission. Independent power producers (IPPs) have not, until now, been widespread in continental Europe.

The principal problem, caused by the present structure of the industry, for the introduction of competition in generation and supply is the integration of generation and transmission. Large consumers, who often take electricity directly from the high voltage transmission grid, may be unable to secure access to imports or electricity from IPPs because the incumbent generator controls the grid. This is one of the problems that TPA is designed to address. Distribution companies may also have problems of access if they are not part of the integrated utility, and they may also be granted right of access under TPA. The right of access for distribution companies has been a contentious issue in the debate over the Commission's draft directive, mainly because of concern over security of supply. This is discussed further in the section on policy issues.

The integration of generation and transmission may continue to raise important issues even in a TPA environment. For example, if the utility remains dominant, issues of system security and back-up power may become contentious. In addition, if liberalization proceeds differently in different national systems (for example, with national pools in some but not others) there will be technical issues of integration and commercial issues such as reciprocity. However consideration of these detailed matters is beyond the scope of this study.

5. Scenarios

There is a very wide range of possibilities for evolution towards a completed single energy market. Policy may be changed on a number of dimensions, with a correspondingly diverse set of outcomes. This in turn creates a very large number of potential scenarios. However, the original terms of reference for this study indicated that three scenarios were to be considered, and guidance from the Commission indicated that the three scenarios of principal interest are:

(a) *Base case*. The present situation.
(b) *Increased competition scenario*. This includes partial opening up of the market and negotiated third party access and is broadly consistent with the agreement reached among EU Energy Ministers in June 1996. It is also broadly equivalent in terms of economic results to a single buyer model modified to remove the problems described in the introduction.
(c) *Open market scenario*. This represents a full completion of the single energy market, including full third party access, unbundling, and liberalization of investment.

In outline the scenarios are:

(a) *Base case*. A continuation of the present situation, with national or regional utilities engaging in limited trade.
(b) *Increased competition scenario*. In this scenario large industrial consumers have the right of negotiated access to the transmission system. Any disputes will be settled by arbitration, and this is expected to maintain the price of access to the network within well defined limits. The right of access may also be extended to distribution companies. However, under this scenario, policy influences on prices continue to have an effect through the purchasing strategy of the distribution companies. In all, some 30% or so of the market is assumed to become moderately competitive, with the remainder subject to strong policy influences.
(c) *Open market scenario*. Fully effective compulsory TPA to networks is the key feature of this scenario. It is assumed that utilities are unable to obstruct progress towards more open access to networks. Increased competition within each country, by the creation of non-discriminatory optimal contracting and despatch of all generators (IPPs, imports and utility plant), is considered in the context of this scenario as many of the effects of increased competition are similar, irrespective of whether competition is within a particular Member State, or is the result of trade. The key feature of this scenario is that customers (large industrial consumers or distribution companies) are able to obtain the lowest cost electricity without restrictions, so under TPA national policies that impose higher costs in an individual Member State become unsustainable.[12]

These scenarios represent successive steps towards a fully open and competitive market. They reflect different degrees of competition and market openness, which is the key feature of the completion of the single market. In line with the original Terms of Reference, differences are attributable only to differences in the level of market integration, and not to other considerations.

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12 Cost differences can persist provided that they are not greater than the cost of transport.

5.1. Ownership

The issue of ownership of generating plant and networks is also important. Both market structure and ownership are likely to have an influence on efficiency. The consequences of privatization in the UK provide evidence of this. Major efficiency gains have been made by the state owned Nuclear Electric, because it has been operating in a competitive environment. Productivity (measured in p/kWh produced) has increased at 12% p.a. since liberalization, mainly reflecting the extremely poor previous performance of the plant. However, additional efficiency improvements have also been made by privatized distribution companies operating in a non-competitive environment, because a clear regulatory structure has given management incentives to improve performance. Efficiency improvements in the last two years have been some 10% p.a. compared with a historic trend of 2% p.a. (see Appendix A.5 for details of the performance of UK companies since liberalization). In Norway the introduction of comparative efficiency measurement among distribution companies (many of which are municipally owned) has also led to pressure for performance improvement.

In some cases a transfer of ownership may increase gains in the open market scenario. However, ownership is considered, by the European Commission, to be a matter for Member States and not a prerequisite for completing the single market, and so it is not considered explicitly here. The emphasis is on defining the incentive structure to which companies (public or private) are subject, which appears, on the basis of international experience, to be the main influence on behaviour.

The main qualification to this view is that ownership may affect the means by which distribution companies are influenced to conform to national policy objectives under an nTPA environment. The use of state capital (including low discount rate) is another potentially contentious area in which ownership has an influence on scenario outcomes. It is unclear how far the use of state capital would be regarded as anti-competitive under a TPA environment.

In the following section the scenarios are described in more detail. The structures of scenarios are summarized in Figure 5.1, which shows, in outline terms, the main commercial relationships.

5.2. Detailed description of each scenario

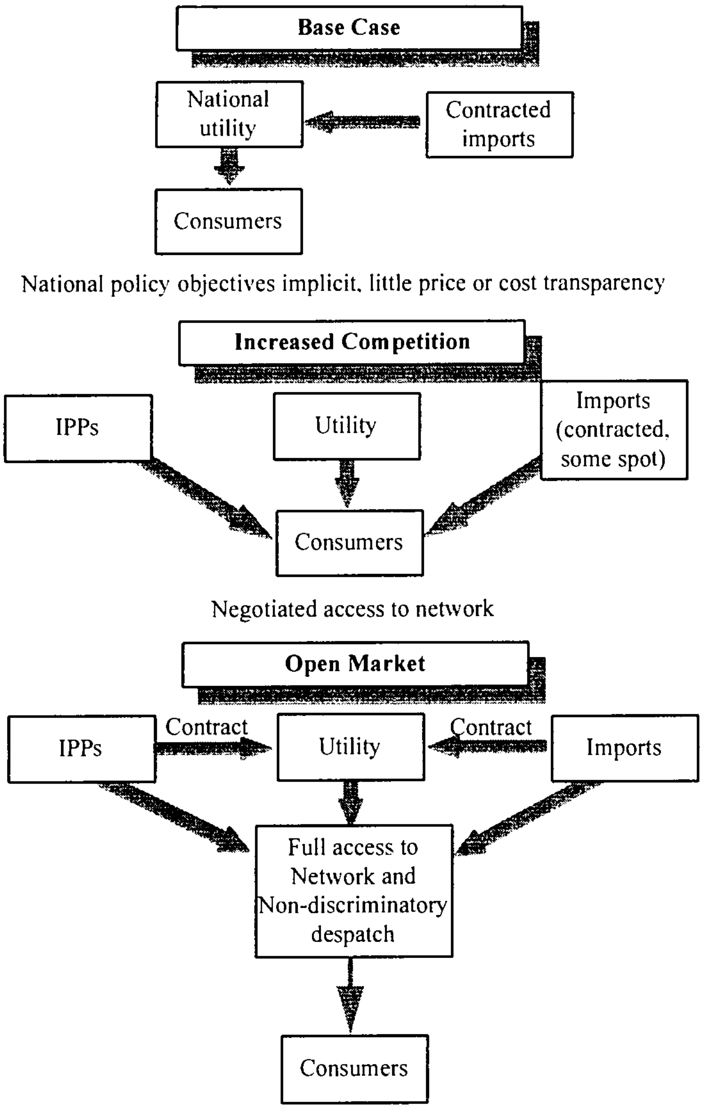
This section describes the three scenarios in greater detail.

5.2.1. Present situation (base case scenario)

This scenario represents a continuation of present institutional arrangements and national policies. National or regional monopolies continue, as do present exclusivity and demarcation rights. The Transit Directive (OJ L 147, 12.6.1991) and Procurement Directive (OJ L 199, 9.8.1993) do not have a significantly greater impact than at present. Regulatory structures are largely unchanged.

Institutions continue to operate broadly as at present. Levels of trade, costs and prices continue to follow present trends. This includes the continued evolution of existing policy. For example, it is assumed that the high costs of German coal are met by direct tax subsidy, rather than a levy on electricity prices, resulting in a fall in the price paid by generators from present levels. This is due to occur from 1996.

Figure 5.1. Structure of scenarios for electricity



Open buying and selling of electricity with unrestricted access to networks

5.2.2. The increased competition scenario (nTPA)

Larger consumers (and perhaps distribution companies) have the right, at least in principle, to purchase their own imports via the existing transmission system. This results in some degree of effective competition. However, distribution companies, supplying smaller consumers, are assumed to continue to be subject to the influences of national policy. This influence may be explicit if the distribution company does not have access to the network, or may be implicit through indirect influence, including via state or municipal ownership.

The Commission has stated that measures aimed at achieving public service obligations must be defined to fall into one of five categories:

(a) security of supply;
(b) quality of supply;
(c) regularity of supply;

(d) price of supply;
(e) protection of the environment.

The scope of these is presently unclear, but for the purpose of this report, it is assumed that policy will continue to have an influence in the following areas:

(a) security of supply and capacity margins, which a distribution company may regard as a key issue;
(b) plant type (technology etc.), including favouring local generation (combined heat and power (CHP), autogeneration, etc.);
(c) diversity of fuel choice, which relates to the distribution company's security of supply;
(d) sources of fuel, which may be affected by local, regional or national policy concerns;
(e) environmental objectives (including taxes), which may be subject to strong political concern;
(f) setting of prices to meet social objectives. The issue of the existence of cross-subsidy is complicated by difficulties in unambiguously allocating costs.

For the increased competition scenario to deliver economic benefit it must involve access to significant amounts of lower cost generating capacity. For this reason it is assumed that purchase of electricity from IPPs or by import becomes a realistic possibility for large industrial users. The present physical constraints on the European transmission system are partially removed, but some constraints remain.

The scenario does not extend to ensuring strict merit order despatch across trading nations because most trade is assumed to be governed by long-term energy and capacity contracts. There are limited changes to the behaviour of existing utilities because national policy objectives remain to some extent, and only a part of the market is open to competition. However, the transit directive is assumed to become more widely invoked. The increased competition scenario allows cost differences to persist because the market remains imperfect. Such differences may result from:

(a) national policy objectives (see above);
(b) differing tax regimes (e.g. environmental taxes);
(c) different fuel prices (e.g. due to use of indigenous resources);
(d) choice of technology;
(e) encouragement of energy efficiency/CHP/DSM;
(f) indirect subsidies, including favourable financial terms from the state for debt etc.;
(g) differences in national regimes, for example in environmental, health and safety legislation and enforcement.

Trade flows are restricted by policy as distribution companies continue to favour local generation, subject to cost competitiveness of the national utility. However, costs are expected to influence trade flows. If costs of the national utility do not converge to those of potential imports and IPPs, there is assumed to be an increase in the amount of imports and IPP production bought by the distribution company.

A fully functioning single buyer model,[13] incorporating the modifications proposed by the Commission, may achieve some of these gains. However, there remain important differences of principle between a nTPA environment and a SBM, and this scenario more closely resembles nTPA.[14] The net effect of the scenario may be that approximately 30% of the market becomes somewhat competitive. The figure of 30% was chosen to be in the mid-range of the figures under debate (following the Italian proposal designed to overcome the negotiating obstacle arising from differences between Member States) when the modelling work was carried out in late 1995 and early 1996. It is close to the subsequently agreed figure of 33%.

5.2.3. Open market scenario

Under this scenario there is full access to the network, both within a country and between countries, and all distribution companies and large consumers have the right to buy electricity independently from any source. Extending the interpretation of the Transit Directive (OJ L 147, 12.6.1991) to apply to a wider range of parties, including those taking at lower voltages (e.g. 110 kV), may be a first step towards full TPA. TPA provides access to both imports and IPPs within a country. This is assumed to be accompanied by the introduction of non-discriminatory optimal despatch, to facilitate the purchase of electricity from other sources, and to optimize despatch within the country. National utilities may remain, but they are prevented by regulation from exercising market power, and are likely to be horizontally and vertically unbundled. The introduction of competition and TPA within any country to facilitate EU-wide trade and competition is at least as important in this scenario as the removal of restrictions on international trade itself.

Under full competition the market develops rapidly, with buyers actively seeking more favourable terms from producers. Indigenous producers are forced to compete with both exports and IPPs selling direct to customers. Novel forms of contract and commercial relationship emerge and there is continuing downward pressure on costs. The existence of a market makes prices more transparent, and enables all buyers to readily assess whether they are paying above the market price for electricity. Consumers buy from the cheapest available source as a matter of routine.

National regulators are likely to be necessary to ensure effective operation of the commercial framework, especially access to the transmission system. There may be some need for a mechanism to resolve disputes at an international level.

There are numerous technical and commercial issues involved with the introduction of competition (e.g. transmission access and pricing, and the structure of spot markets, where these are introduced). These are described further in the Appendices. For the purposes of these scenarios it is assumed that the net effect of these is to give unrestricted, transparent buying and selling of bulk electricity, with sufficient generating capacity available. It need not include a Europe-wide power pool.

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13 Throughout this report, references to the single buyer model refer only to the French proposal, or modifications of it. They do not include the variety of potential structures for a liberalized electricity industry referred to in various contexts as single buyer systems, many of which can involve a large amount of competition.

14 The report by EWI referred to in the introduction reviews the difference between the SBM and nTPA.

This scenario includes the most radical reform, and so provides a useful benchmark against which the effects of partial competition can be judged. The market becomes fully competitive (except for any remaining restrictions on competitive supply to small consumers), with costs forced down to international best practice, and price differentials between markets limited only by transport costs. There is continuing downward pressure on costs as consumers optimize purchases and technological developments produce lower cost energy.

5.2.4. Distribution and transmission

The completion of the single market is assumed to have limited effect on distribution costs, as networks are local natural monopolies. The main driver of costs in these sectors will be the degree of unbundling, and the national policy and regulatory framework for encouraging efficiency. The national policy framework is outside the scope of this study, and so not considered. TPA implies unbundling of transmission costs. This may make the present cost structure more transparent, and so may place downward pressure on costs in the full competition scenario.

A further limitation on efficiency gains may arise if distribution companies are allowed to pass costs through to consumers because the distribution companies will have limited incentives to purchase electricity as cheaply as possible. This limitation is likely to be overcome only by careful regulation of distribution and supply and the eventual introduction of competitive supply to all consumers (as is already scheduled in the UK and Sweden). However, this will be a matter for national policy and is outside the scope of this study.

The natural monopoly characteristics of networks will lead to the need for continuing regulatory oversight to ensure that gains for consumers are secured. Experience in the UK has shown that regulation is most effective where it acts to stimulate competition and provide incentives, rather than seeking to prescribe behaviour in a legalistic manner.

5.3. Summary of scenarios

This section summarizes the three scenarios. The main characteristics of the three scenarios are structural and the assumptions are summarized in Table 5.1.

Table 5.1. Key structural characteristics of scenarios

Structural characteristic	Base case scenario	Increased competition scenario	Open market scenario
TPA to international transmission capacity	No	Yes	Yes
TPA to national networks	No	No	Yes
Non-discriminatory national despatch	No	No	Yes
Physical restrictions on trade	Yes	No	No
Policy restrictions on trade	Yes	Some	No
National control over fuel/technology choice	Yes	Some	No
Equal access to natural resources	No	No	Yes
Tax differences/implicit subsidies persist	Yes	Some	No
Unbundling of transmission costs	No	Limited	Yes
National regulator	No	Arbitration	Yes
Mechanism for resolving international disputes	No	Yes	Yes

Source: modelling assumptions

Costs are discussed to converge in the competitive scenarios, and trade restrictions are assumed to be removed. The broader economic environment is held constant between the three scenarios. The key non-structural assumptions are shown in Table 5.2.

Table 5.2. Other aspects of scenarios

	Base case scenario	Increased competition scenario	Open market scenario
GDP growth etc.	Conventional wisdom[1]	Conventional wisdom[1]	Conventional wisdom[1]
% market liberalized[2]	0	30	100
Fuel prices	Exogenous[3]	Exogenous[3]	Exogenous[3]
Cost convergence	None	Differences reduced by 50% by 2005, 70% by 2010	Difference reduced by, 70% by 2005, 90% by 2010
Restrictions on trade	Trade may not exceed present levels	Average of other scenarios	Unrestricted
Additional capital cost reduction	None	0–1% p.a.	1% p.a.

Source: modelling assumptions
[1] Refers to the conventional wisdom scenario in the Energy Futures to 2020 study.
[2] Defined as large customers and distribution companies having access to the network. Full liberalization, including competitive supply to residential consumers is not included.
[3] See Chapter 4.

5.4. Phasing of scenarios

Each of the scenarios may be examined in isolation with the specified degree of competition imposed uniformly across the EU. However, the introduction of these may be phased, with the Community moving in steps towards a fully competitive market in a co-ordinated manner:

Present situation → increased competition → open market

A more complex alternative, which now appears quite likely, is that individual Member States introduce competition in different ways at different rates. Some countries may go directly to full competition, others may go via an intermediate stage, and others may not reach full competition at all. The introduction of different regimes at different times in the various Member States clearly creates potential problems of reciprocity: allowing each country to determine its own policy, under the subsidiarity principle, would run into limitations because of potential distortions to trade.

For the purpose of this report, we have adopted the simplifying assumption that completion of the single market is co-ordinated across the EU, and measures are introduced at a similar rate. This allows the boundaries to be assessed, and a central case to be identified. In particular, the open market case allows for the full benefits of liberalization, and the base case provides a reference point from which benefits may be calculated. The increased competition case represents one of a very large number of intermediate states, among which are also those with countries proceeding at different rates. The case of all countries proceeding in a consistent fashion in response to the Electricity Directive (OJ L 27, 30.1.1997) is presented here for clarity.

5.5. Assumptions common to all scenarios

The purpose of the scenarios is to assess the effect of completing the single energy market. To achieve this purpose all variables that do not directly influence the consequences of completing the single market are held constant. The assumptions for economic variables are those made for the conventional wisdom scenario in the Energy Futures to 2020 study, in order to retain consistency with other Commission studies. Consequently, the scenarios have a number of common assumptions. This allows the effect of policy measures to be isolated from the effect of other changes.

For example, economic growth will not in itself be a key driver for the completion of the single energy market: it is an external force not under the control of policy. It is therefore kept constant and not changed between scenarios. It is possible that the scenarios would have different outcomes under different GDP growth regimes, so these may be examined as sensitivities, in each case comparing like with like (e.g. increased competition scenario vs. full competition scenario in a high growth scenario, and increased competition scenario vs. full competition scenario in a low growth environment). However, the range of uncertainties on the changes is sufficiently large that these effects are considered to be within the existing range of outcomes.

It is also recognized that there will be some feedback from the consequences of the scenarios, for example the influence of reduced electricity prices on the levels of industrial activity and economic growth. However, these effects are considered to be second order for modelling purposes, because the effects are much smaller than the overall uncertainty in growth forecasts. These feedbacks are therefore excluded from the modelling.

5.6. Costs and benefits of liberalization

Until recent years, electricity industries throughout the world tended to be vertically integrated, with plant construction and despatch managed by a single entity. Some degree of state ownership has also been common, although not universal. However, more recently there has been a trend towards introducing greater competition. This has taken three main forms:

(a) competition in construction of new capacity (IPPs);
(b) granting access to networks to enable competitive supply to consumers (TPA);
(c) introducing power pools to ensure competitive despatch.

The reforms proposed for completing the single energy market include the first two but not the third of these measures, which is regarded as a matter for individual Member States under the principle of subsidiarity.

The main motivations for increasing competition around the world have been:

(a) a desire to introduce private capital into the electricity industry;
(b) a belief that efficiency gains will result from competition.

However, such measures are not always regarded favourably. In particular there is often a belief that:

(a) electricity systems already function reliably and efficiently and there are limited gains to be made;
(b) the costs of introducing competition (set up costs and running costs) are high compared with the benefits;
(c) there is a danger to security of supply;
(d) a competitive system cannot give proper recognition to long-term strategic interests.

This section reviews the experience of liberalization in various countries. It then attempts to assess the potential benefits of liberalization in Europe and to quantify the effects. The costs and potential drawbacks to liberalization are also assessed.

5.6.1. Experience of liberalization elsewhere

Experience of liberalization in electricity is limited because the trend towards liberalization is recent and not yet widespread. The USA now has a long history of IPPs and these have gained a significant market share. IPPs are now becoming common in countries where demand growth is very rapid, such as those in southern Asia. Network access to consumers and pooling arrangements have also been introduced in some countries, most notably the UK, Norway, Argentina and some states in Australia. There are now moves towards greater competition in Australia, South Africa, the USA, and parts of South America. However, in many respects, these reforms remain in their early stages.

The reforms have been aimed at introducing competition more widely and establishing a structure of incentives and prices to promote low cost production and cost reflective pricing. In this way, it was believed that the goals of allocative, productive and dynamic efficiency gains could best be achieved.[15] Table 5.3 summarizes some of the key early gains in four markets where competition has been introduced. In several cases, there are additional gains now accruing. In the countries shown in the table competitive pooling formed the centrepiece of reforms.

Yet it is not a simple exercise to separate the benefits achieved by competitive pooling from the benefits achieved as a result of introducing competitive pressures more generally. For example, privatization accompanied liberalization in the UK and served to encourage the privatized electricity companies to seek efficiency gains. Similarly, it is not easy to distinguish between underlying trends in efficiency improvement and the incremental gains that can be attributed to the introduction of competition. The table focuses on presenting the major changes following the introduction of competition which represent a break from past

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15 Under allocatively efficient conditions the prices of industry inputs and outputs are cost-reflective, so that when resources are purchased they are not misallocated within the sector or in the economy generally. Thus, when consumers make purchase decisions which balance the marginal costs of purchasing a resource with the marginal benefits it provides, they do so on the basis of correct measures of costs and benefits. Productive efficiency means that inputs (whether or not the inputs have been purchased on an allocatively efficient basis) are used efficiently so that a given output is produced with the minimum of inputs. Static productive efficiency refers to short-term operational efficiency, while dynamic productive efficiency includes the efficiency with which capital expenditure is made and technological improvements introduced.

performance and which can (though without formal proof) be attributed to the new competitive pressures.

However, designing competitive markets can involve not only substantial set-up costs but also the introduction of significant transaction costs from creating contracts and regulatory arrangements that bring together functions which were previously the responsibility of one organization. These costs need to be weighed against the prospect of the efficiency gains they are designed to achieve.

The exact benefits achieved from the introduction of competition depend upon the starting position in each country, and some of the examples in the table may not be of direct relevance to continental European utilities. In particular, power pools are unlikely to be introduced on a Europe wide basis. However, the efficiency gains achieved in other countries provide evidence of the main types of improvements that can be produced through competition:

(a) reinforcing the motivation of industry participants to make efficiency gains; and
(b) providing the appropriate flows of information to support efficient decision-making.

Examples of sources of gains include:

(a) productivity gains from:
    (i) improvements in plant performance in terms of availability, thermal efficiency and flexibility of running;
    (ii) reduction in manning levels and improvements in MWh sent out per employee ;
    (iii) more cost effective fuel procurement;
    (iv) allocative efficiency gains from more cost reflective pricing and price reductions;
(b) dynamic efficiency gains from:
    (i) the introduction of new generating technology;
    (ii) rationalization of investment in new capacity.

Most of these gains appear to flow from the introduction of competition itself rather than from any particular organizational arrangements. Power pools do not appear necessary to achieve the majority of these gains. The applicability of different types of gains is discussed further below.

5.6.2. Potential sources of gains from competition in Europe

There is a diversity of potential gains from competition. We have classified these into gains from trade and various types of efficiency gains. The efficiency gains are also indirectly among the benefits of trade, as increased trade creates competitive pressure to increase efficiency. Consequently, all of these gains are potential benefits from completing the single energy market.

Table 5.4 summarizes these gains. Each is discussed further in the next section (5.7).

Table 5.3. The benefits of competition

	England & Wales	Argentina	Norway	New South Wales
Reform	Open access pool Privatization Unbundling	Open access pool Privatization Unbundling	Open access pool Unbundling	Closed pool Business units separate
Market culture	✓	✓	✓	✓
Productive efficiency gains				
Labour	50% reduction in numbers by NP/PG; NP output per employee increased from 7.2 GWh p.a. in 1989/90 to 17.4 GWh in 1994/95	30–35% reduction in numbers at C.Puerto and C.Costanera; C.Puerto increased capacity per employee from 0.47 MW in 1990 to 1.21 MW in 1994	20% reduction at Oslo Energi	n.a.
Fuel	Reduction of coal subsidy by UK£ 1 bn p.a.; NP reduced fuel costs from 1.9 p/kWh in 1990/91 to 1.7 p/kWh (current prices) in 1993/94 Exploitation of lower cost gas	n.a.	n.a.	n.a.
Plant performance	NE availability improved substantially: 46% increase in AGR output Reduction in expenditure on repairs and maintenance: for NP reduced from UK£ 250 m in 1992 to UK£ 213 m in 1994 Increased flexibility of plant operation	Thermal plant unavailability reduced from 60% to 20%	n.a.	Reduction in forced outage rate from 6% to 5% Improvement in thermal efficiency and operational procedures Increased flexibility of plant operation including two-shifting
Dynamic efficiency gains	8.5 GW coal plant retired; 9.5 GW new CCGTs from existing generators and IPPs with consequent improvements in thermal efficiency: 38% for coal to around 50% for CCGTs	Private sector investment in 1231 MW plant Neuquen against pool price risk	Reduction in annual rate of investment in generation by over 50% while consumption increased at under 2% p.a.	n.a.
Allocative efficiency gains	Half hourly pool prices responding to demand/supply conditions introduced, though some problems with dominance of NP/PG Average real price reductions of 10%	Wholesale price reduction of 40% from winter 1993 to summer 1995	Contract price reduction of 38% (partly due to water availability) and for domestic consumers of 2%, reduction of cross-subsidy between industrial and domestic sectors	Pool prices dominated by coal contracts but reflecting load shape

Notes: NP = National Power; PG = PowerGen; NE = Nuclear Electric; AGR = Advanced gas-cooled reactor.
Central Puerto and Central Costanera are main successor companies to SEGBA.

5.6.3. Conditions necessary to realize these gains

As noted above, the experience of liberalization in other countries has tended to involve pooling arrangements. It is therefore difficult to separate which gains are due to competition in general and which are specific to the establishment of pools. Based on our knowledge and experience of these markets in practice, we believe that pooling arrangements are not necessary to realize most of these gains, although in some circumstances it may be desirable or may reinforce the gains. Gains identified as specific to pooling are excluded from Table 5.4. For example, pooling provides strong incentives for increasing plant availability and reducing fuel costs for existing plant. TPA is unlikely to be sufficient for all of the potential gains in these areas to be realized and such gains are thus excluded. Other benefits, such as gains to allocative efficiency, may be realized under TPA, but to a more limited extent than under a system involving pooling.

Table 5.5 shows the gains we have assumed to apply in each scenario following the classification shown in Table 5.4. The introduction of IPPs and network access is likely to create many of the conditions for gains to be realized.

Table 5.4. Gains from liberalization

Trade	Allocative efficiency	Productive efficiency	Dynamic efficiency
• Use of least cost plant across countries • Facilitation of trade with Eastern Europe • Reduced plant margin due to greater interconnection • Ability to exploit differences in times of peak demand • Siting of plant in least cost country	• Reduced cross subsidies between classes of consumer	• Lower operating costs	• Lower construction costs, reduced cost overruns, etc. • Fuel choice on economic grounds • Optimal siting of new plant

Table 5.5. Gains under each scenario

Potential gain	Base case scenario	Intermediate competition scenario	Open market scenario
Use of least cost plant across countries	No	Yes	Yes
Facilitation of trade with Eastern Europe	No	Yes	Yes
Reduced plant margin due to greater interconnection	No	Yes	Yes
Ability to exploit differences in times of peak demand	No	Yes	Yes
Siting of plant in least cost country	No	Yes	Yes
Reduced cross-subsidies between classes of consumer	No	No	Yes
Lower operating costs	No	No	Yes
Lower construction costs, reduced cost overruns, etc.	No	Some	Yes
Fuel choice on economic grounds	No	Some	Yes
Optimal siting of new plant	No	No	Yes

5.7. Preliminary quantifications of sources of gains

Each of these effects is now described in turn. Preliminary quantifications of the effects are described, based on approximate assumptions about the scale of potential gains. More detailed quantifications of the effects of liberalization are described in the subsequent sections on modelling.

Initial analysis is presented here to develop basic indications of the orders of magnitude of gains, and to assist in identifying the major sources of gains. These preliminary quantifications also give a benchmark against which modelling results can be judged, but do not directly affect the modelling itself. The estimates are based on broad judgements of the magnitude of efficiency savings, drawing on cost and price comparisons and the experience of liberalization elsewhere. Such estimates are inevitably judgemental, even with the use of best available evidence. Experience in the UK and elsewhere, where efficiency gains have been larger than expected, provides evidence of the difficulty of making reliable estimates of the scale of gains in advance. Given these uncertainties we believe that simple and transparent estimates of this nature offer useful insight into the scale and sources of gains.

Quantifications are based on a total cost for new baseload generation (the long-run incremental cost of new plant) of ECU 0.04/kWh. This includes operating, fuel and investment costs and a return on capital. The cost would be higher for new midload plant, but new plant usually goes into baseload, and midload demand is usually met by older plant with partially or fully amortized capital costs. Demand in the EU in 2000 is expected to be 2,500 TWh, giving a total long-run cost of generation, adopting this simplification, of ECU 100 billion p.a. This is a very large sum, and the savings achievable are therefore large in absolute terms, even if they are only a small percentage of the total. Specifically each 1% saving in total costs results in a saving of ECU 1 billion p.a. in the long term. Putting in a higher cost for midload and peak capacity would clearly increase the figure, and thus the absolute savings derived below (provided they remain constant in percentage terms), so this figure may be taken as a lower bound.

Distribution costs are assumed to be fixed, and any savings on unit transmission costs or reduction in losses from better optimization are ignored. Fuel costs are also assumed to be fixed and to comprise 25% of total generation costs. Non-fuel operating costs account for 15% of the total, and capital costs the remaining 50%.[16]

The gains from each source are outlined and summarized in Table 5.7, which also shows the extent to which they are expected to apply in each scenario.

5.7.1. Benefits of trade

Use of least cost plant across countries.[17] Increased interconnection will allow the optimal despatch of plant across countries. However there will be transport costs to be paid. The savings from this source are not expected to be large. For example, assuming that a 10% saving on non-fuel variable costs is achievable, and that this applies to additional trade equivalent to 5% of total generation, implies a saving of ECU 0.1 billion p.a.

Facilitation of trade with Eastern Europe and Norway. Trade with countries outside the EU may be made easier by the liberalization of markets. In particular, there is potential for expanded trade with Norway and exports from plant in Poland located close to low cost coal supplies. However, again the effect of this is likely to be small provided that generation within the EU is efficient. This is because savings will not be large compared with the cost of efficient generation in the EU since the cost of fuel transport is a small proportion of total costs. Assuming an additional 6 GW (i.e. about 10% of a large country's system) of baseload imports (40 TWh) with a total saving of 10% over indigenous production generates savings of ECU 0.2 billion p.a. Savings on imports from Norway may be greater than this, but there is limited potential for additional exports without diverting power from indigenous use in energy intensive industries, and so far there has been an apparent reluctance to do this. There may, however, be indirect benefits if the threat of imports causes EU generators to increase their efficiency.

Reduced plant margin due to greater interconnection. This is potentially a more significant source of gains. Plant margins are required to cope with unexpected demand peaks and unexpected plant outages. Exceptionally high demand on two systems simultaneously is less likely than on one (although it may occur, e.g. due to widespread cold weather), and simultaneous plant outages on two systems would also be very rare. Greater interconnection can therefore be expected to result in cost savings due to avoided investment in new capacity.

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16 The breakdown of costs is based on a large coal plant. Gas has proportionately higher fuel costs, nuclear plant proportionately higher capital costs.

17 This is in no way related to Least Cost Planning, which refers to integrated consideration of supply and demand side investments.

We have estimated savings on the basis that additional interconnection eliminates the need for spare capacity sufficient to cover two large units becoming unavailable. Two large units are assumed to be equivalent to 4% of total capacity (based on the maximum size of generating units in the larger markets, e.g. two 1,000 MW units on a 50 GW system). The avoided spare capacity is assumed to be reflected in avoided investment in gas turbines. Total EU generating capacity is some 550 GW, and if 4% of this (22 GW) were to be avoided at a gas turbine capital cost of ECU 300/kW, this would result in an annualized saving of ECU 0.7 billion p.a. If capacity margins were further reduced savings would be correspondingly greater.

Ability to exploit differences in times of peak demand. System peaks in different countries or regions do not necessarily coincide and interconnection may help balance this, again reducing the need for capacity. Some of these gains are already being realized, for example due to the interconnector between France and the UK. The gains are similar in character to the reduced need for plant margin noted above, because additional capacity is required at the peak. There will also be some additional gains from least cost despatch. However, to avoid double counting, savings from this source are assumed to be small.

Optimal siting of plant. The tendency towards more open trade may result in the siting of plant outside the country in which the power is consumed. The siting of plant in Eastern Europe is a special case of this. However, it is not clear that any country within the EU should have a natural comparative advantage: similar plant is likely to be built, often by the same companies constructing IPPs under turnkey contracts. In view of the high costs of long-distance electricity transport (mainly due to power losses), the long-term trend seems likely to be towards siting plant close to demand. However, as noted above, the potential to site plants elsewhere will put competitive pressure on generators to conform to international best practice. This is likely to result in efficiency gains. The effects of trade in this respect are therefore likely to be significant, but indirect, and they are considered under the heading of efficiency gains.

5.7.2. Efficiency gains

Reduced cross subsidies between classes of consumer. The benefits here will arise from correct price signals leading to efficient allocation of resources within the economy. In particular the reduction in subsidies to large industrial consumers and to residential consumers, where these exist, will result in long-term gains.

Immediate effects may not be large. Demand for electricity is relatively price inelastic, and for commercial consumers electricity is only a small component of costs, and therefore not a key determinant of business profitability. For energy intensive industry, the capital costs are sunk and therefore price rises are less likely to cause premature closure, although they may deter the siting of new plant. Furthermore any price rises due to the removal of cross-subsidies are likely to be compensated for in the medium term by efficiency gains.

In the light of these considerations, gains from the removal of cross-subsidy appear likely to be long-term, and partly indirect. There must also be some question as to the extent that such gains will be realized, especially if distribution companies are not granted rights to buy electricity freely under TPA. The retention of any exclusive market share may result in the retention of the ability of the incumbent generator to continue cross-subsidy. short-term gains may be further reduced by temporary economic dislocation (stranded assets and redundant resources).

Lower operating costs. If competition leads to increased efficiency, then operating costs may be directly reduced. This is a potentially very large source of gains where there are significant inefficiencies at present. A potential saving of 10% on non-fuel operating costs leads to savings of ECU 1.5 billion p.a. Such estimates seem modest in view of the increases in efficiency that have followed liberalization in the UK. However, pressure to reduce operating costs is expected to be less severe in the intermediate competition scenario and assumed to apply only to the 30% of the market open to competition.

Lower construction costs, reduced cost overruns, etc. This is potentially a source of very large gains. A 10% saving on the 50% or so of total costs accounted for by capital leads to potential savings of ECU 5 billion p.a. (i.e. 5% of the total) in the open market scenario. This includes both avoided investment costs and avoided interest payments (return to debt and equity) on avoided investment. These savings may be expected to apply to the 30% or so of the market open to competition in the increased competition scenario. There is also likely to be a reduced effect on the remaining 70% of the market. In all, savings in the increased competition scenario are estimated as 65% of those in the open market scenario.

Table 5.6. Preliminary estimates of sources of potential gains

Potential gain	**Amount at stake (billion ECU)**	**Magnitude of saving**	**Estimated saving under TPA (billion ECU p.a.)**	**Estimated saving under nTPA (billion ECU p.a.)**
Use of least cost plant across countries	15 (total operating costs)	10% on 5% of generation	0.1	0.1
Facilitation of trade with Eastern Europe	1.6 (40 TWh at ECU 0.04/kWh)	10% of total costs	0.2 (plus indirect benefits)	0.2
Reduced plant margin due to greater interconnection	6.6 (cost of 22 GW of GT capacity)	Annuitized saving on this much capital (10% annuity factor)	0.7	0.7
Ability to exploit differences in times of peak demand	Small	Small	Small	Small
Siting of plant in least cost country	Indirect	Indirect	Indirect	Indirect
Reduced cross-subsidies between classes of consumer	Small, long-term	Small, long-term	Small, long-term	Small, long-term
Lower operating costs	15 (total operating costs) (5 in nTPA)	10% cost reduction due to competition	1.5	0.5
Lower construction costs, reduced cost overruns, etc.	50 (32 in nTPA)	10% cost reduction due to competition	5	3.2
Fuel choice on economic grounds	15 (premium for uneconomic fuel choice)	20% of total plant now chosen on economic grounds that otherwise would not be	3	2.0
Optimal siting of new plant	Indirect	Indirect	Indirect	
TOTAL			10.4	6.7

Fuel choice on economic grounds. This is a further source of large potential gains. We assume that the optimal choice of generating technology leads to a 15% saving in costs, based on the difference between the cost of a new coal plant and of a new CCGT. We further assume that 20% of present plant is chosen sub-optimally for new generating capacity. This may be an underestimate in view of the large differences in plant mix within Europe, and the limited evidence to date of the willingness by utilities to invest in CCGT, although this is clearly the lowest cost choice. This leads to potential savings of ECU 3 billion p.a. Again, savings in the increased competition scenario are estimated as 65% of those in the open market scenario. As noted, such gains exclude savings from using cheaper fuel for the same type of plant as a result of more effective purchasing, although clearly there is some potential for such gains.

Optimal siting of new plant. Gains here are probably limited, although there may be an indirect effect in encouraging cost savings, because the threat of locating plant elsewhere may force costs down.

In total these differences suggest total available savings of about 10% from liberalization.

5.7.3. Effect on consumption

Table 5.7 shows estimates of long-run elasticities of demand for electricity. Elasticities are below 1 in all sectors, i.e. a 1% change in the price causes demand to change by less than 1%. These estimates are consistent with others. The use of GDP to forecast demand growth in most models emphasizes that demand is not especially sensitive to price.

Table 5.7. Long-run price elasticity of electricity demand (% change in demand/% change in price)

Sector	Long-run price elasticity
Residential	-0.6
Commercial	-0.2
Industrial	-0.4

Source: Helm, Kay and Meyer, *The Market for Energy*, Clarendon Press, 1989.

If the cost savings achieved are reflected in an equivalent price decrease, the industrial electricity price will fall by almost 10% (as this is only a little above the cost of generation). Residential and commercial prices will fall by slightly less in percentage terms, as prices are higher because of additional distribution costs.

Changes in demand can be approximately estimated on the basis of the 10% cost saving in generation, the prices shown below, and the elasticities in the table. These are weighted by the sectoral demand data given in the previous section. This leads to an overall estimated change in consumption of 2%. This is equivalent to about 1–2 years' demand growth.

5.8. Costs of liberalization

The costs of the administrative system necessary in a liberalized market are significant. The major cost is in operating pooling arrangements, which costs less than UK£100 million p.a. in

England and Wales.[18] However, this includes many costs which would be incurred anyway in planning despatch, and this is not part of the proposals presently under consideration. The regulation of access and access charges is much less expensive. The cost of regulation in the UK (which includes all aspects of regulation, including consumer protection etc.) is UK£ 10 million p.a.[19] The cost of regulation in Norway is significantly lower than this. Regulation of access and access pricing accounts for only a modest proportion of this. The cost of introducing the proposed access regimes should therefore be small, although the companies themselves will also incur modest additional costs.

The view has been where markets have been liberalized, that the modest administration costs of liberalization are exceeded by the potential gains. The main qualification to this is that there is a need to avoid the very cumbersome regulation and high degree of litigation that has occurred in the USA. There will be a need to ensure that any such problems are avoided during the implementation of reform in Europe. There appears to be some danger of significant costs in view of the continuing resistance of some Member States to the liberalization process, which may lead to extensive disputes. However, the costs of liberalization are in any case likely to be significantly outweighed by the gains.

5.9. Price comparison

In order further to gauge the likely potential for savings from completion of the single market, we have compared electricity prices across Europe. These are shown in Table 5.8 for each of the main sectors. The variations between countries appear much larger than can be accounted for by differences in national circumstances or exchange rate fluctuations alone. Prices to the residential sector vary by almost 50% from the lowest, prices to industrial consumers by over 70%, and prices to commercial customers by over 100% (Greece is excluded from these comparisons due to the anomalously low prices). In some cases these differences clearly represent different cost allocations. For example, Belgium had among the highest residential prices but among the lowest industrial prices. However, this does not account for all the differences: for example, prices in Germany are high in all sectors, and prices in the Netherlands are low.

In many cases the differences are significantly greater than the savings of approximately 10% or so identified as available from completion of the single market. This suggests that the price and cost convergence that would be expected to follow from completion of the single energy market could yield significant gains, and that the estimate of 10% derived in this section may be conservative.

We have also examined the level of price reductions achieved in the past few years (see Table 5.9). For a mature commodity such as electricity the rate of price reduction would be expected, broadly speaking, to match the rate of economic and productivity growth in the country concerned, excluding exogenous factors such as world fuel prices.[20] This should be the case

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18 The direct cost of the pool itself is some UK£ 30 million p.a.

19 Annual budget for the Office of Electricity Regulation (Offer). The utilities themselves may also incur additional costs of approximately this amount.

20 Fuel prices should not have been quite stable since 1987, falling slowly in real terms approximately in line with the trend suggested, so this is not a major influence over the period shown.

even if operations are already efficient. The potential gains for inefficient operations will be greater. We see that some countries have secured significant price reductions, notably the Netherlands and Ireland. However, in other cases the average price fall across sectors is less than 2%. The absence of large price reductions in these countries again raises questions about whether prices are as low as they would be in a competitive market with full pressure to reduce costs.

The position of the UK warrants specific comment as it is the market with the longest experience of liberalization. Prices are among the lowest in the residential sector and about the middle of the range for the industrial sector. Average price reductions over the last five years are towards the middle of the range (better than average for industrial and commercial customers, worse than average for residential customers). However until recently almost all the gains form liberalization have gone to shareholders (who have seen very large returns) rather than consumers, reflecting the favourable terms put in place at the time of privatization to ensure its success. Over the next five years, many of the gains will feed through to consumers as competition increases and regulation tightens for the natural monopoly parts of the business. For example, there have already been large reductions in charges for transmission and distribution, which will continue, and falls in electricity generating costs should also flow to consumers to a greater extent as contractual arrangements expire. It is estimated that prices to the residential sector will fall by some 20% between 1995 and 2000 (see Appendices for forecasts of price reduction and estimates of efficiency gains in the UK). Price falls to industrial and commercial consumers are also expected to be significant. This will give the UK among the lowest prices in Europe in all sectors. Again, these considerations suggest that the estimate of savings of 10% or so of costs is conservative.

Table 5.8. Comparison of electricity prices in Europe in 1995 (1990 UK pence per kWh)

Country	Residential (excl. VAT)	Commercial	Industrial
Belgium	9.68	5.30	2.91
Denmark	7.94	2.91	2.63
France	8.72	4.45	2.85
Germany	9.83	7.31	4.74
Greece	3.06	2.19	1.49
Ireland	6.51	4.68	3.00
Italy	7.70	6.34	3.50
Luxembourg	8.58	6.26	3.94
Netherlands	6.21	3.41	2.74
Portugal	7.53	4.31	3.31
Spain	7.56	4.31	3.06
UK	7.26	4.10	3.12

Source: LE estimates based on UK Electricity Association data.

Table 5.9. Reduction in prices 1990–95 (percentage p.a. real terms excluding VAT)

Country	Residential (excl. VAT)	Commercial	Industrial
Belgium	1.6	0.7	1.6
Denmark	3.2	4.7	3.4
France	0.7	-1.2	-0.9
Germany	1.2	1.3	2.0
Greece	4.6	4.7	6.8
Ireland	3.1	2.9	2.9
Italy	n.a.	n.a.	n.a.
Luxembourg	2.2	-0.5	0.9
Netherlands	3.5	3.7	1.8
Portugal	-1.2	1.9	2.6
Spain	0.0	2.6	3.0
UK	0.3	3.8	3.3

Source: LE estimates based on UK Electricity Association data.
Note: Negative number indicates price rise.

6. Modelling of scenarios

This chapter describes the use of models to enhance and refine the estimates of the savings available from completion of the single market for electricity. Two well established models of the European electricity industry have been used:

(a) the EIREM model developed by EWI;
(b) the MIDAS model developed by NTUA.

The assumption on data input (plant capital costs etc.) are described in Chapter 4 and in the Appendices, and are consistent between the two models.

6.1. Modelling approach

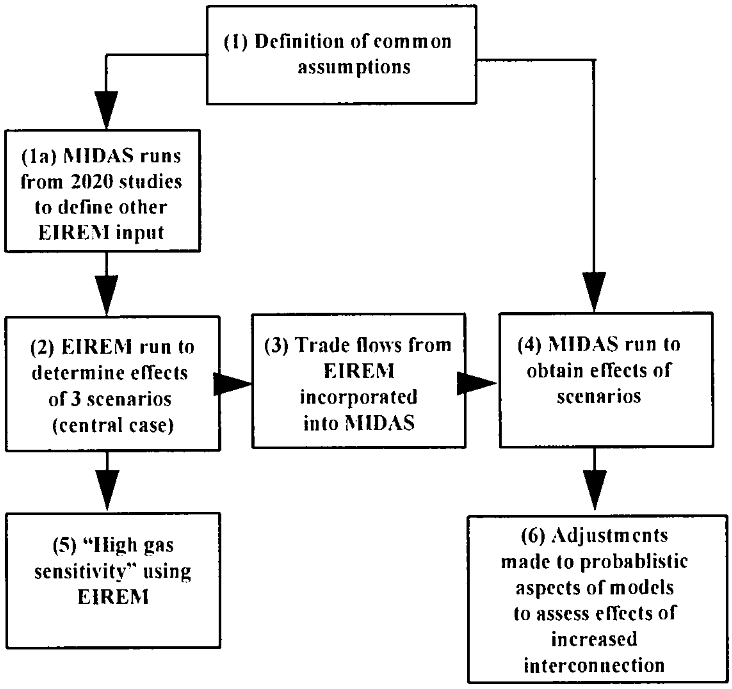
The EIREM model calculates the least cost way of meeting a specified level of demand from a mixture of generating plant and power imports. Unit costs of various technologies, fuel prices and electricity demand are treated as exogenous variables in the model. The cost of new transmission capacity is explicitly included. This allows the magnitude of changes in costs and trade patterns arising from the scenarios to be identified. EIREM treats the expansion of generation and transmission capacities and their utilization within a unified framework. Building and utilization decisions over the entire time horizon are made so as to minimize the present value of overall system costs of meeting a given demand pattern, assuming perfect foresight with respect to cost parameters and fuel prices. Resulting expansions of transmission capacity are rational (according to this criterion) even if utilization rates may drop in the long run. Thus, transmission capacity expansions are entirely a consequence of cost differences between neighbouring areas. EIREM assumes 10% transmission losses per 1,000 kilometres.

Italy is treated as an exogenous variable in the model because Italy already has a large import share, which is unlikely to increase even under competition. Even if this were to happen for strictly economic reasons, it would most likely be avoided for political reasons (national independence). Analysis based on cost minimization alone is therefore likely to give a misleading picture. The UK is also treated exogenously because its electricity system is already liberalized, and therefore is a special case.

The MIDAS model is more elaborate, and well suited to refining the results. It covers all energy sectors and ensures that results for the electricity sector are reasonable in terms of interaction with other sectors. The MIDAS model also provides a cross check that the trade flows identified in the EIREM are consistent. Among the major advantages of the MIDAS model is that it includes probabilistic elements, including system outages. This allows it to be used to model the cost savings arising from increased interconnection.

The way the models have been used, and their interactions, are shown in Figure 6.1.

Figure 6.1. Structure of model runs



6.1.1. Stage 1: definition of common assumptions

The assumptions for the MIDAS and EIREM models were made consistent, choosing the same value for each key input variable. The key variables are:

(a) unit capital costs for each type of plant,
(b) unit operating costs for each type of plant,
(c) fuel price assumptions,
(d) discount rates,
(e) generating capacities,
(f) thermal efficiencies,
(g) plant life,
(h) exogenous assumptions imposing restrictions on plant construction (e.g. restrictions on commissioning of new nuclear plant).

The assumptions are those used in the Energy Futures to 2020 study for the Commission. Quantitative assumptions are also broadly consistent with independent estimates from London Economics and EWI. The major difference is that London Economics make slightly more favourable assumptions on costs and thermal efficiencies of CCGT plant. However, such assumptions would only further strengthen the already very strong position of gas in the marketplace.

The EIREM model also requires that demand is specified. This is taken from the conventional wisdom scenario in the Energy Futures to 2020 study.

The modelling treats the UK and Italy as exogenous due to their special characteristics. The UK is already close to being a fully liberalized market, and most of the remaining barriers to competition will erode over time. In 1998 supply to the residential sector is to be opened to competition and contracts for generation based on indigenous coal generation are due to expire. This should make the UK market at least as competitive as that envisaged under the TPA scenario. It is therefore considered appropriate to maintain the UK unchanged between the three scenarios. There may be additional opportunities for UK exports to continental Europe, but in practice these seem likely to be small, and it seems more probable that gas will be exported to IPPs in Europe rather than IPPs being built in the UK for export.

The situation in Italy is also assumed to be policy driven. At present it imports large amounts of power, and the presumption is that this would not increase under other scenarios. Italy is assumed to achieve self-sufficiency by 2005 in line with ENEL and UNIPEDE assumptions. By this time costs are assumed to be sufficiently harmonized to avoid further trade flows. Savings derived from the EIREM model are adjusted assuming similar unit savings to those achieved elsewhere.

6.1.2. Stage 2: modelling of scenarios using EIREM

The EIREM model has been used to estimate the effects of liberalization under the defined input assumptions. The EIREM model is a cost optimization model, producing the lowest cost means of meeting demand. The scenarios are represented as follows:

(a) *Open market (TPA).* An unconstrained run of the model corresponds to the full competition scenario. Costs are shown to converge close to common levels (90% of present differences being eliminated) equivalent to present best practice and there are no restrictions on trade. A general decrease in capital costs of 1% p.a. is also included as a separate case.

(b) *Increased competition (nTPA).* In the negotiated TPA scenario there is some convergence of costs, and import restrictions are reduced from present levels, but some cost differences persist. Cost differences are assumed to be reduced by 70% over the period 2000–2010. Trade restrictions are entered exogenously between present levels and those in the full competition scenario.

(c) *Present situation.* In the present situation, costs continue at present levels, and trade is restricted to present levels.

6.1.3. Stage 3: incorporation of the trade flows in MIDAS

The MIDAS model is very elaborate, and for practical reasons it treats each country individually. Trade flows are specified off line to be consistent with the results for each country. This is clearly to some extent an iterative process.

The trade flows from the EIREM model are incorporated into MIDAS, along with the other input assumptions.

6.1.4. Stage 4: MIDAS run to obtain the effects of the scenarios

MIDAS is run to obtain the outcomes of the scenarios. The results are generally consistent with those of EIREM. As would be expected with two different models, there are minor differences in output. However, these are mainly country specific and do not affect the overall picture.

6.1.5. Stage 5: high gas case

EIREM has also been run with a gas price constant throughout the life of the model. This shows a very high penetration of gas. EIREM was used for this case rather than MIDAS because it treats the European system as a whole in a straightforward fashion.

6.1.6. Stage 6: high interconnection case

High interconnection has been modelled by assuming that a lower level of national system security is acceptable than would be the case in the absence of interconnection because additional interconnection provides additional back-up. The MIDAS model has a probabilistic element and is therefore able to examine the probability of loss of load on the system (in terms of hours per year). The effect of interconnection is modelled by allowing this to increase in the absence of interconnection, assuming that interconnection would in practice prevent this from occurring.

7. Results of modelling work

This chapter describes the results of the modelling work. Tables 7.1 and 7.2 summarize the results for the key economic variables of prices, costs, consumption and trade. This shows gains under the intermediate competition scenario, with further gains under the open market scenario. Tables 7.1 and 7.2 show results, respectively, with and without cost savings in capital and operating costs, a major source of potential gains. Savings are clearly much greater, in Table 7.1, which includes additional capital cost saving.

These estimates are from the modelling, and are broadly consistent with the approximate estimates shown in Chapter 5 showing gains of ECU 4–10 billion p.a., about half of which is attributable to reduced construction and operating costs. The majority of the remaining savings are due to optimal fuel choice. Increased system interconnection will also contribute to gains. The savings are long-run savings. Electricity generating plant has a long operational life, so gains from reduced investment costs take a long time to realize in full, because it takes many years for all plant to be replaced by new investment.

The remainder of this chapter considers the results in more detail. The results from the EIREM and MIDAS models are considered together, as the results from the two models are broadly consistent.

7.1. Prices

The issue of prices is not directly addressed by the EIREM model. We have adopted the assumption that price changes reflect cost changes. The change in prices between the scenarios is therefore calculated as equal to the change in the average costs of supplying electricity.

This is an average effect and there may be indirect effects on sectors not able to gain access to the network due to a redistribution of prices. For example, under nTPA and TPA prices to large industrial consumers are expected to become more cost reflective, as they are able to buy directly from generators. If the price is above cost they will choose to buy directly, and the existence of more transparent pricing is likely to make existing utilities increasingly unable and unwilling to subsidize industrial consumers, although a desire to retain market share may lead to predatory pricing in some instances.

Distribution companies will continue to retain their ability to set prices which are not cost reflective to the market segments. This is because they will be able to disguise their allocation of costs etc., since charges for access to distribution networks will not be transparent. However, their potential to do this will be more restricted if they have the ability to buy direct, because prices for different load patterns will become more transparent.

Under full TPA, prices for bulk electricity will become fully cost reflective as the market becomes much more competitive and transparent. However, other elements of the chain, in particular distribution, will continue to lack transparency for the foreseeable future, and be subject to varying cost allocation. There is, therefore, likely to be some retention of cross-subsidies between different consumer groups.

As noted in the preceding chapter, there are expected to be indirect long-term gains in allocative efficiency, but these are not treated by the model.

Table 7.1. Key results of scenarios: including reduction of construction costs due to competition

	nTPA		TPA
Price difference from base case (average total costs ECU/MWh long term)	1.8		4.0
Total cost savings (billion ECU p.a., equal discount rate, long term)	Generation	4.5	10.0
	Transmission	0.04	0.08
	Distribution	0 (considered fixed)	0 (considered fixed)
Consumption[1]		0–2%	1–3%
Volume of trade (TWh p.a.)	2000	192	261
	2010	192	264

[1] From off-line calculation/MIDAS model.

Table 7.2. Key results of scenarios: excluding reduction of construction costs due to competition

	nTPA		TPA
Price difference from base case (average total costs ECU/MWh long term)	1.4		2.1
Total cost savings (billion ECU p.a., equal discount rate, long term)	Generation	3.6	5.4
	Transmission	0.03	0.06
	Distribution	0 (considered fixed)	0 (considered fixed)
Consumption[1]		0–2%	1–3%
Volume of trade (TWh p.a.)	2000	175	217
	2010	162	193

[1] From off-line calculation/MIDAS model.

7.2. Costs

Non-fuel costs fall in the nTPA and TPA cases, reflecting the effect of increased competition. Fuel costs are exogenous, and change in line with the assumptions reported in Chapter 5 above. They do not vary between scenarios.

The assumptions show that a rise in gas prices causes gas fuelled capacity to become uncompetitive with coal fuelled technology after 2005, with a consequent reduction in the amount of new gas fired capacity that is commissioned. The idea that gas will become uncompetitive appears potentially unrealistic in view of the supply cost analysis presented in the gas work, and an alternative scenario with lower gas prices is described below. This shows a continuing growth in the market share of gas. However, other considerations, such as security of supply, are likely to prevent gas completely dominating the market for new generating capacity, even if its price is very competitive with that of other fuels.

7.3. Demand

This is also considered exogenous in the EIREM model. We have therefore not estimated the effects on demand here. However, changes would be expected to be small: electricity demand is inelastic in response to price changes, and other drivers of demand, especially GDP growth and technological change, are kept constant across the scenarios. This is confirmed by the MIDAS model, which includes elasticities.

7.4. Trade

Trade tends to increase in the short term under TPA as present cost differences can be exploited. In the longer term there is a response from the utilities in high cost areas to cut costs, and trade decreases in the longer term.

7.5. Costs and fuel shares

The liberalization of the market tends to lead to convergence of fuel choice across the EU. Gas is favoured over coal as long as the gas price remains at present levels, leading to a very large increase in the market share of gas in the scenario showing sustained low gas prices. If gas prices rise, there is a general switch to favour coal. French nuclear power may also increase its market share if the cost advantage shown by some data is realizable in a competitive market.

Each of the results are now discussed in more detail for the various countries.

7.5.1. Germany

In general, one would expect that the share of coal generation (which is capital intensive) is reduced and that of gas increased when moving from the present situation to competitive scenarios. However, in the case of Germany the possibility of importing in a competitive environment leads to a retention of the coal intensive generation structure, which is not possible under the base scenarios, imports making up the shortfall. Consequently, the market share of coal is less under base case than under competitive scenarios. The dominance of coal in the competitive scenarios is further reinforced by the fact that coal-based generation in Germany, which is initially rather expensive, becomes cheaper as costs converge to best practice.

7.5.2. France

In France, both coal and gas are boosted in the longer term by increased competition. The reason why this effect occurs only in the longer term is the current excess capacity of nuclear power. The crucial assumption underlying this result is the cost reduction in non-nuclear generation (which is currently considered more expensive in France).

7.5.3. Benelux

Benelux imports large amounts of power from France, Scandinavia and Germany. Import restrictions under base case lead to new capacity requirements which are satisfied by gas fired units, whereas these capacity expansions can be avoided under competitive scenarios as in Germany. Therefore the gas share is higher and the coal share lower under base case than under competitive scenarios. As in the case of Germany, coal-based generation increases its market share in the course of time because this technology benefits more from cost convergence for best practice than does gas-based generation.

7.5.4. Austria/Switzerland

The results for Austria/Switzerland are shaped by the assumption that coal and gas based generation is initially more expensive than elsewhere and that under competition, costs are reduced substantially. This leads to coal- and gas-based generation being substantially larger under competition than in the base case.

7.5.5. Spain/Portugal

In this region, the choice of scenarios has only a small influence on fuel choice, because this region is the least expensive one, even in the base case.

7.6. Import shares

The import share is greater under the full competition scenario, reflecting the removal of restrictions. It is lower under the negotiated TPA scenario, as some restrictions remain, and lowest under the present situation. Imports increase to 2000 as present cost differences give rise to trade to exploit these.

Figure 7.1. Share of imports in total demand

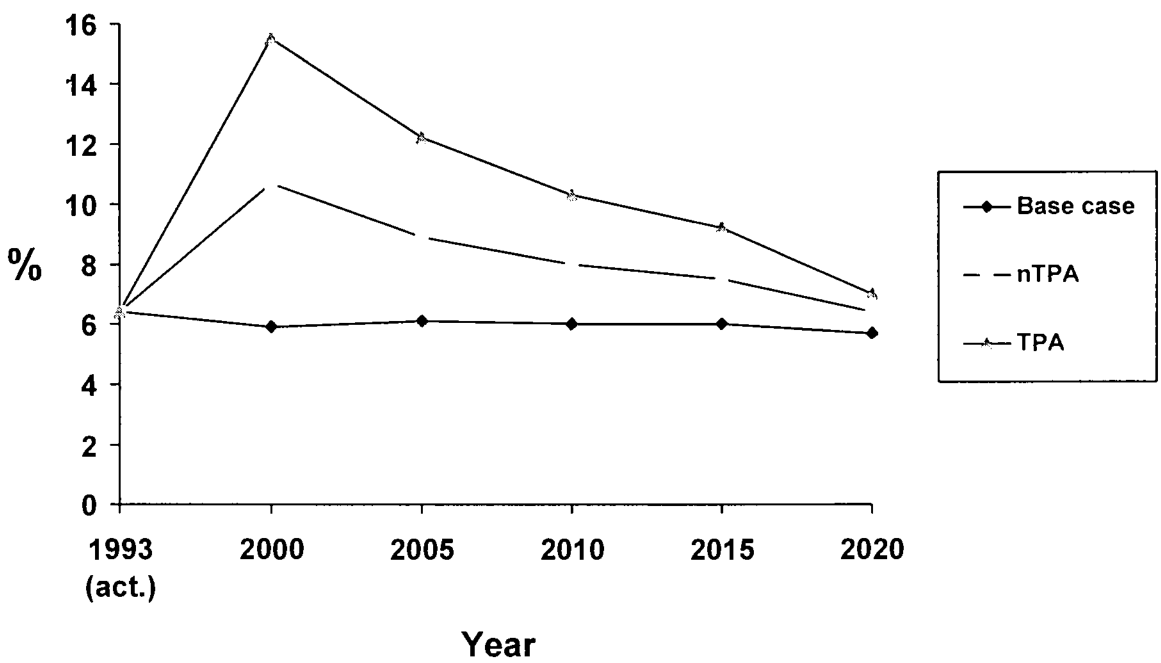


Figure 7.2 shows the total share of imports in the regions covered by the EIREM model, imports expressed as a proportion of total production. After that date the import share starts decreasing due to increasing harmonization of costs. Figures in the Appendices show this for each country.

The situation in each country is now reviewed.

7.6.1. Germany

Qualitatively Germany is similar to average. As long as cost differences persist, the import share may be as high as 20% under TPA.

7.6.2. France

Import share is generally very small (less than 1% until 2010). Under nTPA and TPA scenarios it increases significantly after 2010 because the cost advantage of French nuclear power is gradually eroded by generation cost reductions in other countries. Yet, in absolute terms, the import share remains rather small.

7.6.3. Benelux

Qualitatively Belgium is similar to the average. The maximum import share may be some 25% under TPA.

7.6.4. Austria/Switzerland

The share of import peaks in 2000, then decreases. Eventually, it is smaller in the competitive scenarios than in the base case. The reason for this is the assumed cost reduction under competition, which does not take place in the base case.

7.6.5. Spain/Portugal

This region is a high cost producer on the basis of assumptions derived from the Energy Futures to 2020 study. Therefore the single market leads to a strong increase in imports. With the cost disadvantage reducing in the course of time, imports decline strongly.

7.7. Trade and transmission capacities

The capacity of transmission connecting markets increases greatly under the more competitive scenarios.

The strongest expansion due to the single market concerns the connections France–Benelux and France–Germany which presently have a relatively low capacity. The connections Germany–Austria/Switzerland and Germany–Benelux do not change, as they already have large capacities. The connection between France and Austria/Switzerland almost doubles under full competition, and that between France and Iberia increases by some 50% under nTPA and full competition. Additional transmission requirements arise in particular with respect to French exports. Under TPA substantial additions of transmission capacity from France to Germany (5,000 MW), Benelux (6,000 MW), Switzerland/Austria (4,000 MW) and Spain/Portugal (1,500 MW) would be required. The explanation for these requirements lies almost exclusively in the excess capacity and cost advantage of French nuclear power in the short term in combination with the sizes of the corresponding import markets. Such changes may, of course, cause political difficulties which reduce the effect from that shown here.

The changes in trade flows under competition are summarized on the maps (Figure 7.). These show imports and exports (measured in TWh) in 1995 and 2010 under the TPA scenario. Detailed figures are shown in Appendices.

7.8. Requirements for additional transmission links between Member States in the Commission's TENs proposals

Table 7.3 compares the new capacity requirements identified by the modelling with the new links planned as part of the TENs programme. A total of 15 GW of new transmission capacity are identified as being required under the Commission's proposals.

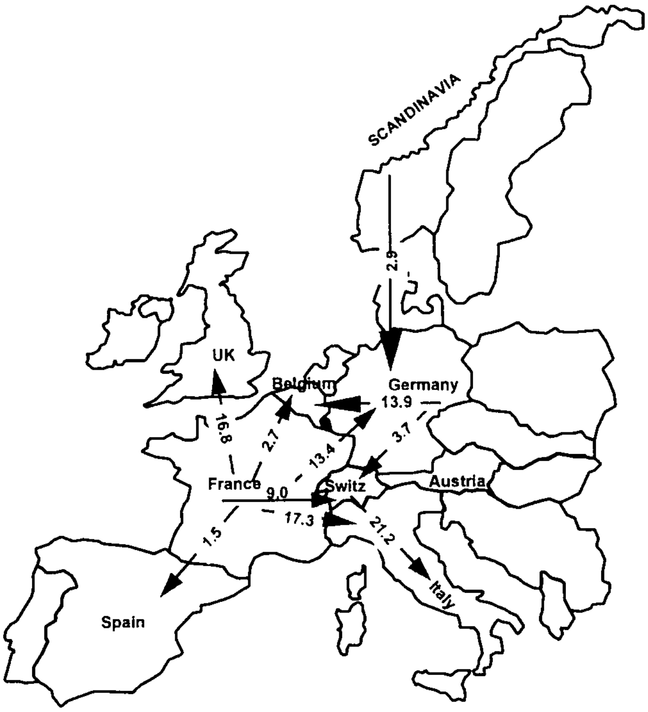
Table 7.3. Comparison of proposed and modelled additional capacities

Country	Details	Proposed capacity (MW)	Modelling of required new capacity (MW)		
			Base case	nTPA	TPA
Germany–Denmark	Bjaeverskov–Bentwisch	600	1.200[1]	1.200	1.200
France–Belgium	Moulaine–Aubange	2 x 1.100	0	2.000	6.000
France–Italy	Grande Ile–Piossasco	2 x 1,500	0	0	0
France–Spain	Cazaril–Aragon	2 x 1,600	0	1.500	1.500
Belgium–Luxembourg	Aubange–Bertrange	1,400	n.a.	n.a.	n.a.
Spain–Portugal	Aldeadavila–Douro Int Meson–Lindoso	2.800	n.a.	n.a.	n.a.
Finland–Sweden		300	n.a.	n.a.	n.a.
Austria–Italy	Lienz–Sandrigo	1.500	400	400	400
Total		15.000			

[1] Scandinavia total.

Figure 7.2. Trade flows in TWh under TPA

1995



Note: arrow to Spain includes exports to Portugal; arrow to Switzerland includes exports to Austria

2010

Note: arrow to Spain includes exports to Portugal; arrow to Switzerland includes exports to Austria

The model shows large increases in linkages with Scandinavia being required. The 600 MW planned link with Denmark should make a useful contribution to this. The model also shows increases in the linkages for France with Spain and Belgium which are in line with the Commission's proposals. The model does not show a large increase in capacity between Italy and Austria or France (although some increased linkage with Austria is shown). However, such links may be required for operational or security of supply reasons that are not reflected in the model. Alternatively, there could be a less rapid return to self-sufficiency in Italy than is envisaged in the modelling assumptions, and this could result in the requirement for such a link. There are other links on which the model does not produce a view because they are considered part of integrated regions (e.g. Belgium and Luxembourg are considered together in the model).

As noted, liberalization increases the amount of new capacity required, and in particular the links between France, Spain and Belgium are greater in a liberalized environment.

7.9. High gas case

The EIREM model has been used to analyse the potential for increased use of gas for generation if prices remain low.

In the main scenario, the percentage of generation from gas rises from its historic level of 6% to 14% in 2010, before declining to 22% in 2020. However, in the case of a consistently low gas price, the market share of gas in generation reaches 20% by 2010 and 35% by 2020. Such very large levels of gas use would clearly cause major security of supply concerns and these are addressed in the following chapter.

7.10. Increased interconnection

The MIDAS model confirms that increased integration of markets leads to benefits from reduced capacity margins. The estimates derived in Chapter 5 are consistent with the modelling.

7.11. Other issues

7.11.1. Share of 'new technologies' (i.e. combined cycle) in overall capacity

The market scenarios do not necessarily have a significant or unique effect on the share of new technologies. Table 4.1 shows the market share of combined cycle technologies under each scenario according to the EIREM model. Their share will be highest in Germany and the Benelux and somewhat lower in Iberia, whereas in France and Austria/Switzerland it will remain quite low. The reason for the latter is the ongoing dominance of nuclear and hydro, respectively. Nevertheless, the percentage increase in France and Austria/Switzerland in 2000–2020 is quite large (growing from a small base). It can be seen that increased competition leads to an increase in these technologies – in comparison with the base case – only in France, being a low cost region with major export capacity. In the other regions, importing is preferred to building additional 'new' capacity.

The main effect of the scenarios in this respect is to make the high gas use case more likely. This would clearly lead to a major increase in the amount of combined cycle plant.

7.11.2. Capacity utilization: generation plant

Table 7.6 shows capacity utilization in each scenario. The change in capacity utilization rates in each scenario partly reflects the corresponding changes in fuel shares. For example, in Germany, gas combined cycle tends to be used less under increased competition, whereas the opposite is the case in France. The utilization rate of conventional hard coal fired plant increased in France, the Benelux and Austria/Switzerland under competition because these countries experience a cost reduction of this technology. Increased competition leads to a lower utilization rate of gas combined cycle in the Benelux and a higher one in Austria/Switzerland.

7.11.3. Capacity utilization: networks

In the long term, when trade declines, increased competition has little influence on the utilization rate of networks. In the intermediate term, when competition induces large trade flows, there is in some cases a strong increase in utilization rates. A typical example is the case of France. As shown in Table 7.5, increased competition leads to a substantial increase in the intermediate-term utilization rate of networks from France. The increase in utilization rates takes place in addition to induced capacity additions. Since the expansion of network capacity is effectively permanent whereas the increase in trade is generally more short-lived, network utilization rates may eventually be smaller under increased competition than in the base case. However, the EIREM model, which is based on perfect foresight, ensures that such links are still economic even if utilized fully for only a few years.

7.11.4. Investment in generation

Table 7.7 shows investment in generation in billions of ECU. Note these figures are comparable with Table 7.1, and include the additional savings in investment costs. It should also be noted that the savings quoted in Tables 7.1 and 7.2 are long term annualized savings and therefore represent the cumulative effect of investment cost savings (annualized), which continues to grow beyond the period shown in Table 7.7 (which simply shows an investment saving over a particular period). For example, Table 7.7 shows a saving of approximately ECU 10 billion (or nearly 20%) over the five-year period 2015 to 2000, which is an annualized saving of some ECU 1 billion p.a. (assuming an 8% discount rate). If such investment savings were realized every five years over a typical investment cycle (based on plant life) of 40 years, this would lead to an investment saving of ECU 80 billion.[21] This is equivalent to an annual cost saving of some ECU 8 billion p.a., including interest payments and return to shareholders.

In the intermediate term, investment expenditures tend to increase in some cases under increased competition because of the capital intensive coal based generation gains share. In the long term, unit investment costs converge to best practice, and investment expenditures consequently decline under increased competition. Investment requirements are reduced in the high gas case.

21 Compared with ECU 500 billion or so of total capital tied up in the EU electricity system (assuming an average capital cost of ECU 1,000/kW).

7.11.5. Investment in networks

Table 7.8 shows investment in transmission in millions of ECU. Increased competition will lead to substantial additional investment in transmission networks in the early years, to accommodate increased trade in the medium term. In the longer term, investment in networks will not be very much greater under the liberalized scenarios as generation costs converge.

Table 7.4. Share of 'new' technologies (%)

Country	Scenario	2000	2010	2020
Germany	Base case	14.4	28.3	51.7
	nTPA	10.5	26.5	51.7
	TPA	10.8	26.0	51.6
France	Base case	1.9	9.1	9.2
	nTPA	1.9	10.1	9.9
	TPA	1.9	10.3	10.1
Austria/Switzerland	Base case	0.5	6.8	9.0
	nTPA	0.5	6.8	7.2
	TPA	0.5	6.8	6.5
Benelux	Base case	25.6	33.2	44.0
	nTPA	24.7	36.4	45.6
	TPA	24.9	36.4	46.3
Iberia	Base case	0	13.3	32.4
	nTPA	0	12.6	30.9
	TPA	0	13.4	30.7

Source: EIREM model.

Table 7.5. Capacity utilization of networks – example: exports from France (%)

France 2010				
Scenario	**Germany**	**Austria/Switzerland**	**Benelux**	**Iberia**
Base case	63	50	35	23
nTPA	72	53	54	42
TPA	89	54	56	43
France 2020				
Scenario	**Germany**	**Austria/Switzerland**	**Benelux**	**Iberia**
Base case	50	53	33	27
nTPA	47	38	37	32
TPA	43	28	35	26

Source: EIREM model.

Table 7.6. Capacity utilization (hours per year), 2020

	Germany			France			Austria/Switzerland			Benelux			Iberia		
	Base case	**nTPA**	**TPA**	**Base case**	**nTPA**	**TPA**	**Base case**	**nTPA**	**TPA**	**Base case**	**nTPA**	**TPA**	**Base case**	**nTPA**	**TPA**
Coal	7.148	7.148	7.148	6,015	6.519	6,984	1.503	5,785	6,490	3.995	7.166	7.166	7.157	7.157	7.157
IGCC	7,617	7,617	7,617	0	0	0	0	0	0	0	0	0	7.617	0	0
CCGT	6.762	6,762	6.762	0	0	0	0	0	0	0	6.027	6.027	0	0	0
Brown coal	7,437	7.437	7,437	0	0	0	0	0	5,089	0	0	0	0	0	0
Oil CC	4.992	4,453	4.183	1.058	1.367	1.569	1,099	984	1.856	6,580	4.955	4707	5,473	5.868	5,947
OCGT	0	0	0	6.245	6,293	6,294	7,513	7,513	7,513	7,515	7,515	7.515	7,504	7.504	7,504

Source: EIREM model.

Table 7.7. Investment in generation capacity (billion ECU)

Country	Scenario	2005–10	2015–20
Germany	Base case	12.0	30.8
	nTPA	12.9	28.9
	TPA	10.6	25.7
France	Base case	6.0	11.6
	nTPA	5.3	11.6
	TPA	5.4	10.4
Austria/Switzerland	Base case	1.9	1.8
	nTPA	0.8	1.4
	TPA	0.7	1.3
Benelux	Base case	3.2	3.4
	nTPA	3.5	2.0
	TPA	3.1	1.8
Iberia	Base case	5.1	4.7
	nTPA	4.8	3.6
	TPA	3.7	2.6
Total	Base case	28.2	52.3
	nTPA	27.3	47.5
	TPA	23.5	41.8

Source: EIREM model.

7.11.6. Environmental consequences in terms of CO_2

Table 7.9 shows CO_2 emissions under the main scenarios. Until about 2005, there will be less CO_2 under increased competition because a larger share of overall power generation will be accounted for by French nuclear power. In the longer term, there may be more CO_2 under increased competition, because of the increase in coal based generation following a rise in gas prices. Of course, the latter does not occur in the 'high gas case', and as we judge that an increase in gas usage is in practice most likely in the TPA environment, this should ensure a continuing environmental benefit.

These environmental benefits may be counterbalanced to some extent by the increase in 'visual pollution' from an increased number of transmission lines, presuming they are not underground, and the potential increased emissions of methane from systems outside the EU (see Part B of this report).

Table 7.8. Investment in networks (million ECU), 1994–2000

Country	Base Case	nTPA	TPA
Germany	1.583	1.931	2.400
France	6	788	3.239
Austria/Switzerland	93	241	814
Benelux	2.772	3.085	3.966
Iberia	0	0	461

Source: EIREM model.

Table 7.9. CO_2 emissions in main regions[1] (million tonnes)

	Base case	nTPA	TPA	Gas-TPA
2000	503	479	446	432
2010	509	592	516	442
2020	449	467	471	366

Source: EIREM model.
[1] Excluding Italy, the UK, Greece and Sweden, which are not covered by the EIREM model.

8. Conclusions and policy implications

8.1. Conclusions and policy recommendations

The model runs show substantial gains for consumers under increased competition. These amount up to ECU 4–6 billion p.a. under nTPA (increased competition scenario), and ECU 10–12 billion p.a. under TPA (open market scenario) compared with a continuation of the present situation. This is equivalent to some ECU 30 p.a. for each citizen of the EU. The larger gains mainly arise from competitive pressure reducing costs. Examination of present price differentials across Europe suggests these estimates may be conservative. The problems potentially associated with TPA in gas (see Part B of this report) do not apply to the same extent in electricity. This is because the issue of potential oligopoly power in production is less important than for gas, and the location of generation within the borders of the EU makes electricity generation more susceptible to policy influences than gas production.

There may be additional potential for gains from the introduction of competition within countries, in the form of national electricity pools and supply competition. However, this is considered a matter for national policy, to be left to each Member State under the subsidiarity principle. The gains described in this report are limited to those arising from changes at the EU level.

The fully competitive scenario needs to be realized as closely as possible for maximum benefit to be obtained. This implies the following policy outcomes:

(a) TPA to be made available to as wide a range of consumers as possible, including distribution companies.
(b) Mechanisms to ensure non-discriminatory despatch of plant and choice of new capacity to be put in place.
(c) Substantial reinforcement of transmission capacity, especially between France and Iberia, and Benelux and Germany. It may be desirable to support such projects. Financial assistance may not be necessary as they are likely to be justified on economic grounds alone. However, it may be possible to speed up their construction by giving policy support of various types (speeding planning procedures, facilitating negotiations, etc.). The removal of exclusive rights to build new transmission capacity is likely to be a component of this policy support.
(d) The full benefits of the open market scenario also require the unbundling of transmission and the regulation of grid access and charges.
(e) The natural monopoly characteristics of networks will lead to a need for continuing regulatory oversight to enable competition, provide incentives, and prevent abuse of market power.

8.2. Conclusions on issues specified in the terms of reference

The original terms of reference for this study indicated a number of areas which were of particular interest to the Commission. This section of the report summarizes our conclusions on these points. The description is mainly at the level of the Union as a whole. The effects on individual Member States, where these diverge from the Community average, are described above. The consideration is in terms of the following.

8.2.1. Energy consumption patterns

End use consumption patterns do not change greatly, because electricity demand is inelastic, and percentage price changes are not large (except for large industrial consumers). This is because most of the savings are in generation and this is only some 50% of the cost of electricity to a residential consumer (and so cost reductions affect only part of the value chain). Small percentage changes in price lead to even smaller changes in demand. Consequently, the benefits to consumers are likely to come more in the form of price reductions than in additional consumption. Consumption overall is expected to change by some 2 to 3%, little more than a single year's underlying demand growth.

8.2.2. Energy production patterns

The main effects here are an increase in the use of gas and additional production from French nuclear plant in the short term. French nuclear production may not, in practice, increase in the way shown by the EIREM model. Studies by London Economics show alternative patterns of trade. The key result is the potential created for improving efficiency by trade (whatever the precise pattern) and the competitive pressure resulting from this.

8.2.3. Price and effects for certain categories of consumer

As indicated, price falls of ECU 2–4/MWh (8% for most industrial users, a slightly larger percentage for the larger industrial users) are expected in the industrial sector. This will reduce industries' costs accordingly. Price falls of this magnitude may also be experienced by residential and commercial sector consumers, who are served by the distribution network. However the reduced costs of purchasing bulk power may, to some extent, be appropriated by the distribution companies unless there is careful oversight and regulation to ensure that this does not happen, or a more widespread introduction of competition in supply. The percentage price decreases will in any case be smaller (approximately 2–4%) than for industry as the same decrease in ECU/MWh applies to a larger price. (Prices are assumed to be ECU 100/MWh for residential consumers and ECU 38/MWh for industrial consumers when calculating percentage price reductions.)

8.2.4. Levels of investment in capacity and network links

Over the period of the study (to 2020), investment in capacity in the base case is expected to total some ECU 150 billion, and investment in networks is expected to total ECU 13 billion. These totals will be larger in the long term because, as noted above, it takes a long time for all generating plant to be replaced. These are reduced in the competitive scenarios due to reduced investment costs, and more efficient capacity utilization, which more than compensates for any slight demand increase. We estimate savings of ECU 12 billion in the intermediate competition scenario, and ECU 27 billion in the full competition scenario. These estimates are clearly subject to significant uncertainty as the scale of efficiency savings achievable is difficult to estimate, for the reasons stated above. The majority of the savings are achieved in the latter part of the study period when the benefits of competition have taken effect.

Investment in transmission infrastructure initially increases, then decreases as there is less need for trade as costs converge. There also may be some efficiency gains, although these are not explicitly included. Increased interconnection is therefore a benefit of liberalization. There are additional savings from the avoided interest payments (opportunity cost of capital) on the avoided investment (e.g. typically ECU 2.7 billion p.a. assuming an avoided investment of ECU 27 billion at a 10% rate of return).

8.2.5. Capacity utilization

The level of utilization of generating capacity increases, as increased system interconnection allows a reduced capacity margin. This increases capacity utilization by some 16 percentage points.

8.2.6. Level and pattern of cross-border trade and sourcing by independent parties

The level of cross-border trade increases from 6% of total consumption to 15% of total consumption by 2000 in the TPA case. It then declines to 7% of total consumption. This compares with approximately constant trade in the base case. In practice the peak may be reduced to 10–12% by delays in line construction and uncertainties about future trade patterns.

8.2.7. Level of import dependency and sources of imports

The level of import dependency for the Community as a whole remains low under all scenarios. There is some possibility of additional imports from Eastern Europe and Norway in the full competition scenarios, but these are in any case not likely to be significant as a proportion of the total market.

The level of import dependency also decreases for individual Member States in the competitive scenarios. This apparently paradoxical result is due to competition forcing cost convergence between various countries, and electricity being produced close to where it is consumed. No country is considered to have a natural competitive advantage in this respect. However, the benefits for completion of the single market are greater for this reason (as noted above).

8.2.8. Requirements for investment in interconnection

The funds required for investment in interconnection are, as noted above, ECU 13 billion.

8.2.9. Security of supply and balance of energy sources

The Community energy supply is well diversified at present. There is a long-term shift to the use of imported rather than indigenous coal, which may be accelerated under a fully competitive scenario. However, as sources of coal supply are well diversified this is unlikely to raise major security of supply concerns. There is also likely to be an increase in the use of gas in the fully competitive market. This is likely to lead to an increased dependence on imports of Russian gas. It is suggested that this be addressed by the increased use of dual firing and increased strategic storage. This is described further below.

8.2.10. Contribution to the competitiveness of Community industry and broader economic and social effects

As noted above, prices to large industrial consumers are expected to decrease in the long term. This will aid the competitiveness of Community industry where electricity is an important factor of production. This may be mitigated in the short term if cross-subsidies to large industrial consumers are reduced. The magnitude of the cross-subsidy at present is difficult to measure, but experience in the UK suggests that the effects may balance in the short term, with medium- and long-term gains for competitiveness.

For commercial customers, electricity is typically only 2% or so of their costs. These will be reduced by only a modest percentage. The effect on competitiveness is therefore likely to be small.

The UK experience has highlighted the fact that efficiency gains can be accompanied by large falls in employment levels. Output per employee has increased by 120% and 100% for National Power and PowerGen respectively since liberalization (although some of this is the replacement of direct employees by contracting out, so falls in employment are smaller than a simple consideration of company employment totals would indicate). This process is sometimes described as replacing hidden unemployment with actual unemployment because of the fear that those made redundant may not find other employment, imposing significant social and economic costs. The presumption in this report is that benefits to consumers and industry represent the main goal. There is a broader issue of employment policy that arises from present economic trends towards reducing employment levels in many industries, but this is beyond the scope of this study.

8.2.11. Impact of difference in indirect taxation or subsidization of energy consumption

There are presently few taxes on electricity. The completion of the single market may therefore have little effect. Taxes on gas and coal to the power sector are also not widespread, so again the effect would be small. Taxes on oil products are widespread but oil is a minor contributor to the fuel mix in power generation, except in Italy. The effect of taxes is therefore expected to be small.

The main effect on subsidies in electricity is likely to be the removal of cross-subsidies to large industrial users referred to above. Subsidies on indigenous fuel production in Germany, Spain and Greece remain, but there is a trend to make these direct, rather than indirect through the electricity price. This trend may be expected to be accelerated by the completion of the single market. If differing levels of CO_2 taxes are imposed in Member States this may introduce distortions. However, potential economic distortions caused by differing treatments of externalities is a broad subject affecting many industries and so outside the scope of this study.

8.2.12. Environmental consequences

The main environmental effect of the completion of the single energy market is likely to be the increased use of gas, which should reduce CO_2 emissions. The reduction in CO_2 emissions between the low and high gas cases is estimated as 105 million tonnes p.a. Decreased capacity requirements should reduce local environmental disruption, although the increase in interconnection causes additional visual pollution problems from the lines, which may need to be balanced against the benefits. There is also a potential problem with increased emissions of methane (a powerful greenhouse gas) from natural gas systems outside the EU (see Chapter 18).

It may be argued that differences in environmental legislation and practices impose different costs in different countries, which distorts the market. However, the main thrust of policy at the level of the EU is towards harmonization of environmental standards in the energy sector.

To the extent that differences persist, the effect of such differences on trade is a very broad issue affecting many industries, and so beyond the scope of this study.

8.3. Costs of liberalization

There may be substantial transaction and administrative costs. However, such costs must be set against the very large scale of the potential gains. Costs, in the form of additional administrative and regulatory costs, are likely to be of the order of tens of millions of ECU p.a.: gains are forecast to be of the order of billions of ECU p.a. Furthermore, the majority of costs are likely to be incurred in setting up pooling arrangements, which means that they will not be incurred under the draft Electricity Directive (OJ L 27, 31.1.1997). It therefore seems most unlikely that costs will be substantial compared with the potential gains. There is the potential to incur larger costs if the administrative arrangements are not designed to minimize costs. Designing efficient arrangements will be an important challenge for the implementation of the Commission's proposals.

8.3.1. Efficiency of the existing system

It may be argued that the existing system is already efficient, and therefore that the estimated gains from liberalization will not be realized. However, the proposition that there are no existing inefficiencies in any of the EU electricity systems does not appear tenable. Individual plants and companies may be efficient, but cost and price differences and the range of system configurations seem larger than can be accounted for by intrinsic variations in economic circumstances. Where systems are efficient there may be expected to be little change from liberalization, but increased competition will nevertheless act as a valuable discipline to help control costs.

8.4. Security of supply

This is the most difficult and potentially contentious issue raised by the prospect of liberalization. Disruptions of electricity supply could have very far reaching consequences for the economy, and major social effects, so they are considered to be the legitimate domain of policy. Security of supply includes avoidance of both short-term disruptions (e.g. blackouts on a cold winter evening), and longer-term problems (e.g. disruption during the course of a year due to fuel supply problems). The various types of supply interruption and potential responses are described in Table 8.1. Supply interruptions are classified according to duration, because the effects and remedies are very different. Short-term disruption is defined as a system outage of a few minutes to a few hours. Medium-term disruptions are outages persisting to some extent over a period of a week or more. Long-term disruptions are supply problems lasting over a year or more. Short-term local interruptions occur on all systems at present, due to local technical problems. However, more widespread interruptions, or longer-term interruptions, are rare, reflecting the very high standards of security achieved by the European electricity industry.

The need for security of supply is uncontentious, but the necessity for policy intervention to provide security of supply is controversial. The argument that electricity is a necessity is in itself insufficient. For example, food and clothing are basic necessities, but ensuring supply is not the subject of national policy.[22] There are two main reasons why electricity generation may be a special case. The first is that electricity, and to a lesser extent gas, are very expensive to store, and supply must be effectively continuous. The second is that fuels are natural resources concentrated in only a few countries in the world.

Table 8.1. Types of supply disruptions

	Typical sources	Typical remedies
Short term	• Unexpected plant outages	• Plant margins • Interconnection with other systems • Interruptible contacts
Medium term	• Fuel supply disruption	• Diversity of fuel sources • Strategic storage • Multifiring of plant • Interruptible contracts
	• Prolonged, widespread technical problems with plant	• Diversity of plant type • Plant margin (including mothballed plant) • Interconnection with other systems
Long term	• Long-term fuel supply disruption	• Diversity of plants' fuel type • Diversity of fuel sources • Multifiring of plant

The geographical concentration of fuel sources has tended to cause a reluctance to rely on oil, where in the light of events of the 1970s there is still a concern that there may be reliance on the Middle East. Such concern is now extending to gas, where there is concern that Europe may become over-dependent on supplies from Russia and Algeria.

The solution to the problem of potential interruptions to supply is to rely on a diversity of sources for each fuel, to the extent that this is available, and to rely on several different fuel types. Multifiring of plants can help greatly in securing the latter. The cost of security of supply is an insurance premium; the rewards must be balanced against the risks.

8.4.1. Markets can provide security

The first thing that should be noted is that markets are not necessarily less secure than planned systems. Coal in particular has well diversified sources of supply, found in politically and geographically diverse locations (Australia, South Africa, Indonesia, etc.). In the UK, liberalization has seen an increase in the diversity of the fuel mix (at least for the present), and indigenous UK gas is produced by a variety of companies from physically diverse operations. In contrast the UK's pre-liberalization CEGB found itself vulnerable to industrial action in the UK coal fields. The French nuclear programme has certainly reduced dependence on Middle East oil, but it may have left the system open to generic technical problems. The increase in interconnection seen in the TPA scenario will provide a significant contribution to security of supply.

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[22] The Common Agricultural Policy clearly has some influence on food supply.

8.4.2. The case for central intervention

The question then arises of whether insurance against interruptions is needed, and if so who pays. In principle, in a competitive market those who want guaranteed supply will be willing to pay for it, while others may not. For example, an energy intensive industrial consumer might be willing to take the risk of occasional supply interruptions in return for cheaper power, but commercial consumers, for whom electricity is a small part of their costs are likely to be unwilling to risk disruption of their businesses, and so will wish to pay a security premium.

In a market system for electricity the mechanisms for dealing with this are contracts to guarantee supply and high peak prices. High peak prices give an incentive to produce at periods when demand is high, or other capacity is unavailable. Such mechanisms are more tailored to situations of temporary shortage, such as unexpected unavailability of plant or exceptionally cold weather. However, such mechanisms are less likely to be suitable for coping with severe or prolonged shortages, as this would require investment on the small probability of a large payoff, which few organizations would be willing to undertake.

Contract provisions providing for very large penalties in the case of supply interruption are likely to be much more effective. However, given the undeveloped nature of secondary contract markets in most of Europe, such routes are unlikely to be a practical means of securing the desired outcome for an individual consumer for the foreseeable future.

Security of supply also, as noted, has wider economic and social effects and is, in economic terms, a quasi public good, because the benefits of security of supply do not necessarily accrue to those who pay for it. In addition, the main mechanism for security of supply (very high prices when capacity is in short supply) may be politically unacceptable, due to accusations that those charging very high prices were 'profiteering from misfortune'. Security of supply is therefore a legitimate area of concern, and policy intervention may be desirable. However, security of supply cannot legitimately be used to justify any policy which fits particular preferences of the government of the day or the management of a generator.

8.4.3. Potential policy mechanisms

Most of the concern on security of supply is likely to revolve around the effects of interruption to consumers served by the distribution network, because large industrial consumers taking power directly from the transmission network will be less vulnerable to supply interruption and more able to contract adequately on their own behalf. In contrast, there remain problems, such as illiquidity of contract markets and the political problems of high short-term prices, which may cause difficulties for small consumers for whom the cost of supply interruption is great, and where there are significant broader effects of supply interruption. Consequently, a potential means of achieving the desired level of security of supply is to place a legal obligation on the distribution company to ensure security of supply in their region. This will lead to the distribution company contracting for the necessary level of security, while retaining competition in who provides this. This can be achieved, provided that supply to small consumers does not become competitive and the distribution company retains an effective monopoly.[23] An obligation of this type meets the objective of guaranteeing security of supply, while allowing the single energy market to be completed. It clearly implies there should be no restriction on the parties with whom a distribution company is able to contract.

The preferred policy route for addressing security of supply directly in generation is likely to be that of encouraging greater fuel diversity. This may be in the form of IGCC which can use coal or oil, and dual firing of CCGTs, which may be the most cost effective option. Reliance on Russian gas imports is likely to be the largest single concern regarding security of supply in the emerging market. There may be a compulsory requirement for dual firing of plant if the penetration of Russian gas becomes large. The only risk then would be a simultaneous disruption of Russian gas supply and Middle East oil supply for long enough for strategic stocks to be exhausted.[24] This seems extremely unlikely, and would probably leave sufficient time for corrective action to be taken. Encouraging interruptible electricity contracts will have a similar effect to dual firing, and have the indirect effect of increasing gas security because the ability to interrupt supplies to the power sector will free up gas for other uses.

Incentives imposed on generators to achieve security of supply need not distort competition, or significantly dilute its benefits, provided that measures are applied equitably. Mechanisms to encourage dual firing, or any measures related to specifying certain fuels or sources of supply, must be applied in a non-discriminatory fashion, and each player in the market will then compete to provide electricity on the best possible terms given these constraints. In this respect measures to promote security of supply will resemble those which deal with other public goods and externalities such as environmental protection. The policy objective is met, but the imposition of requirements to meet certain standards does not impair the operation of a competitive market.

8.5. Summary of policy recommendations

In summary this study leads to the following policy recommendations:

(a) Third party access to networks should be introduced for as wide a range of consumers as possible. Unbundling of transmission and generation and mechanisms to ensure non-discriminatory despatch of plant should form part of this programme, as should liberalization of investment in independent generating plant.
(b) Additional interconnection will be necessary. The Commission should act to facilitate additional grid connections such as those identified in the Commission's document on trans-European networks.
(c) It may be desirable to place a legal obligation on distribution companies to ensure security of supply under full TPA.
(d) Measures to encourage dual firing of CCGTs are desirable.

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23 The alternative is a fully competitive supply market in which no single party is charged with guaranteeing security of supply. Some individual Member States may go this route, but this is a matter for each under the subsidiarity principle. There are presently no proposals to introduce this on a Community-wide basis.

24 There will also be logistical difficulties in restocking plant running on back-up distillate fuel for more than a short period, which will need to be addressed.

9. Part B: Gas

9.1. Introduction

This part of the report describes the effects of completing the single energy market for gas. First, the European gas industry is described, with emphasis on the characteristics of the industry that most affect the consequences of completing the single energy market. The scenarios for the development of the single energy market are then defined, and the modelling approach to assessing the consequences of the scenarios is outlined. Results of the modelling are then described and their interpretation is reviewed. Finally, policy implications are discussed.

Policy initiatives to introduce TPA, and to complete trans-European energy networks, recognize the central importance of transport in the gas industry, and its natural monopoly and oligopoly characteristics. However, the consequences of reform will depend on the broad industry context in which it is introduced, and the analysis presented here is designed to take account of this context. Economic theory has traditionally tended to concentrate on perfect markets, with large numbers of sellers and buyers, and on monopoly. Neither of these is entirely appropriate to modelling the European gas industry which is oligopolistic in character. Standard oligopoly theory provides useful insights. However, the particular nature of the demand for gas and the pervasive potential existence of rents in the value chain, require care to be taken in the application of the theory. In this context, bargaining theory provides valuable insights, and is applied here.

The industry characteristics which define the most appropriate framework for analysis are:

(a) The small number of producers likely to be able to supply large incremental quantities of gas within the time frame of this study, and their location outside the EU. This implies that oligopoly theory will be relevant to the upstream.

(b) The very large economies of scale in gas transmission capacity. This implies that monopoly and oligopoly theory will be relevant to the downstream.

(c) The availability of substitutes for gas in almost all applications above a certain price, and the lack of substitutes below this. The availability of substitutes above a certain price defines the characteristics of demand, and in particular an effective price ceiling for gas in many sectors. The lack of substitutes at lower prices leads to the possibility of large economic rents if monopoly or oligopoly power is also present.

(d) The separation of production and networks, and their linkage through long-term contracts. This implies a certain structure of industry participants in any bargaining.

(e) The lack of transparency in costs and prices in the value chain. Despite progress from the publication of Eurostat data on prices, information on many topics remains limited. Imports remain subject to bilateral contracts, as do many prices to large industrial consumers. This will affect the structure of bargaining. Limited data availability on costs and pipeline networks also constrains the potential for modelling the industry.

The remainder of this part of the report comprises eight chapters:

Chapters 11–14: review of the industry:

(a) Demand: the competitive position of gas in the energy market and the future level of demand.
(b) Supply: the sources of production available to meet demand.
(c) Value chain: the costs and values in different parts of the supply chain, and the potential existence of economic rent.
(d) Competition and industry structure: the commercial structure of the industry.

Chapter 15: scenarios:

(a) Present trends: a continuation of present industry structures and trends.
(b) Negotiated TPA with independent pipelines: access to networks granted on a negotiated basis, with no monopoly rights over the construction of new transport capacity.
(c) Full TPA: compulsory third party access to pipelines.

Chapter 16: modelling structures: the modelling applies game theory (including bargaining theory) to the oligopolistic structure of the gas industry.
Chapter 17: results of modelling: consequences for prices, consumption, costs and trade flows of each of the scenarios.
Chapter 17: discussion of results. A qualitative and quantitative discussion of the results of the modelling.
Chapter 18: the completion of the single market in energy and the completion of trans-European energy networks.

10. Industry structure

This chapter describes the structure of the gas industry and how this is likely to determine the outcome of the introduction of TPA.

Figure 10.1 summarizes how the various aspects of industry structure determine the context in which liberalization would operate. Most of these factors represent fundamental characteristics of the market, and would not directly be altered by the introduction of TPA. Each is then described more fully in subsequent sections. The factors are (the sequence (a), (b), (c) etc. corresponds to that on the diagram):

(a) How the pattern of demand responds to changes in the price of gas and competing fuels (elasticity). There is a price ceiling for gas set by the cost of competing fuels, but demand is inelastic below this level (Section 11.3).
(b) Steady underlying demand growth (Section 11.4).
(c) The structure of oligopoly producers with incremental production concentrated in three main sources (Chapter 12).

The factors above imply little gas to gas competition at present, with prices to consumers set by the cost of using competing fuels.

(d) Supply costs. The total cost of supply tends to lie below the market price (Section 12.4).
(e) The existence of rents in the value chain determined by the relationship between cost and price (Chapter 13).
(f) Oligopsony buyers at present, with a larger number of buyers under TPA. However, unless TPA is extended to all consumers, which is beyond reforms presently envisaged, the total number of customers (large industrial consumers and distribution companies) will remain small (Section 14.1).
(g) Vertical separation of the industry with production and transmission having different owners in most cases (Section 14.2).

The factors above lead to a process of bargaining for available rents.

(h) The possibility of committing to binding agreements in the form of long-term contracts (Section 14.3).
(i) Imperfect information on costs and prices available to participants in the market (Section 14.4).
(j) Perceived risk of interruption varying between suppliers (Section 14.5).
(k) Extensive regulation (Section 14.6).

These factors influence the bargaining process which will allocate rents between producers, consumers and transmission and distribution companies.

Figure 10.1. Influence of industry structure on the outcome of reform

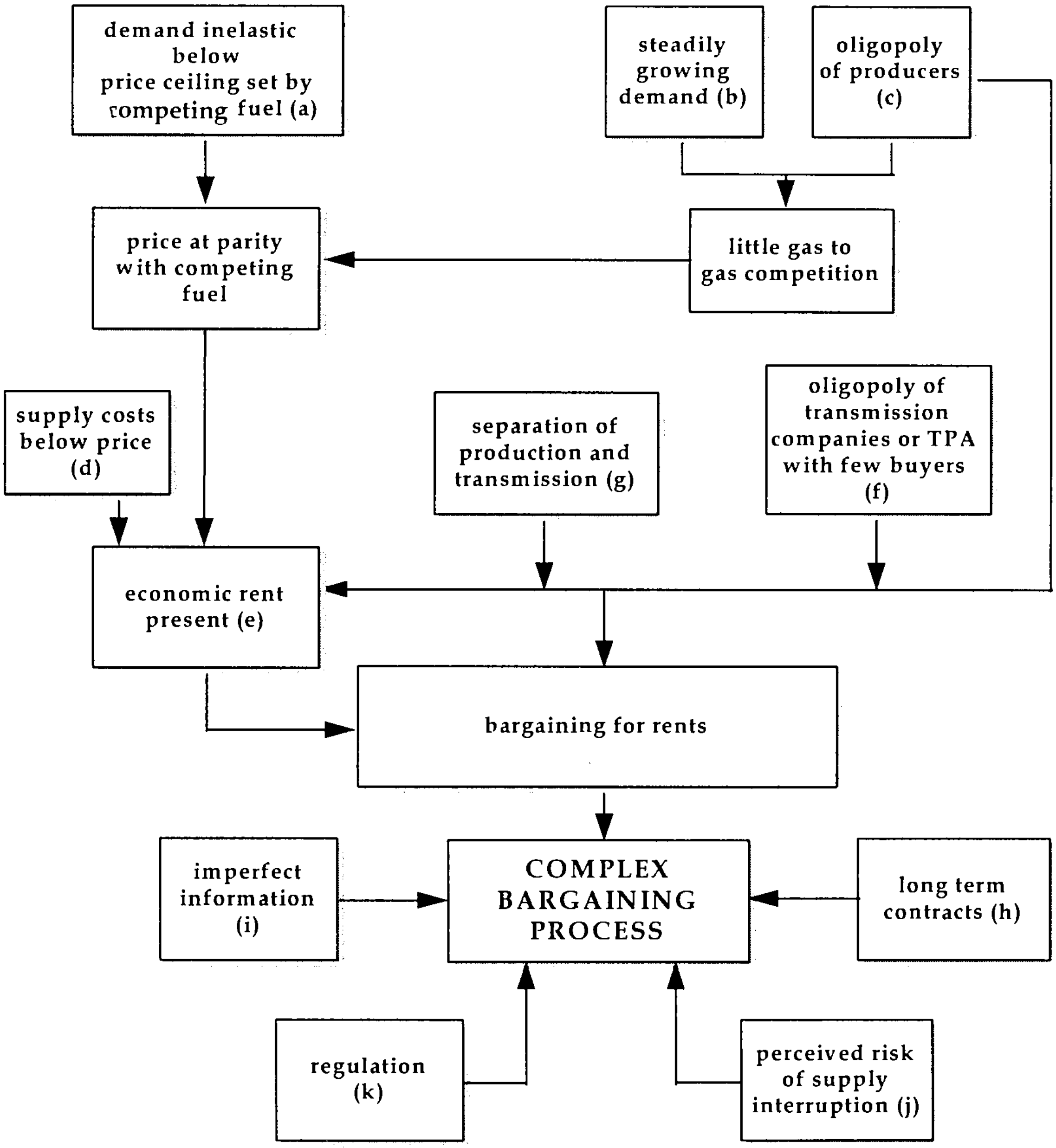


Table 10.1. Key factors affecting the emergence of competition in gas markets

Factor	Europe[1]	UK	US
Number of incremental sources supplying each market	3	40	Hundreds
Multiple independent offshore terminals/pipeline systems, or open access to these	Few	Yes	Yes
Number of independent producers serving each market	3 major incremental	20+	Hundreds
Third party open access to transmission infrastructure	No[2]	Yes	Yes
Third party open access to distribution infrastructure	No	Yes	No
Competitive supply to power sector	No[2]	Yes	Yes
Competitive supply to large industry	No[2]	Yes	Yes
Competitive supply to small consumers	No	Pending	No
Spot market	No	Developing	Yes
Scale of individual geographical markets	Large	Large	Large
Rate of market growth	Rapid in power sector, slow in others	Rapid in power sector, slow (1%) in others	Slow to moderate
Linkage between individual markets	Integrated	Integrated	Interstate pipelines
Export potential	No	From 1998 to continental Europe (and Ireland)	Not outside NAFTA

[1] Excluding the UK.
[2] Under discussion.

10.1. Experience in other markets

There is limited experience to date of the effects of liberalizing natural gas industries. The most extensive experience is from the UK and USA, both of which have competitive supply and extensive TPA. In both cases, substantial competition in the gas market has emerged. However, circumstances in these markets are very different from those in the EU as a whole. In particular, production in both markets is highly competitive, with numerous diverse sources of gas under independent ownership and control. These producers all have acccss to markets via infrastructure that allows buyers access to multiple sources of supply with no 'bottlenecks' under the control of a single authority that would create monopoly power over supply.

Table 10.1 compares the situation in the UK, USA and EU as a whole. The differences in the market structures imply that the lessons from the UK and USA are unlikely to be directly transferable to the EU as a whole. For this reason, we have relied on analysis and modelling, rather than direct analogy with other markets, to assess the likely effect of reforms. The framework used here takes explicit account of the relative lack of competition among producers serving the EU.

11. Demand

This chapter reviews the demand for gas. The characteristics of gas demand, in particular the need to remain competitive with alternative energy sources, have a strong influence on prices, consumption, and trade. In addition, the underlying rate of growth of gas demand affects the balance of influence within the market between producers, transporters and consumers. This chapter examines the characteristics of gas demand and the forecast level of demand over the next 25 years.

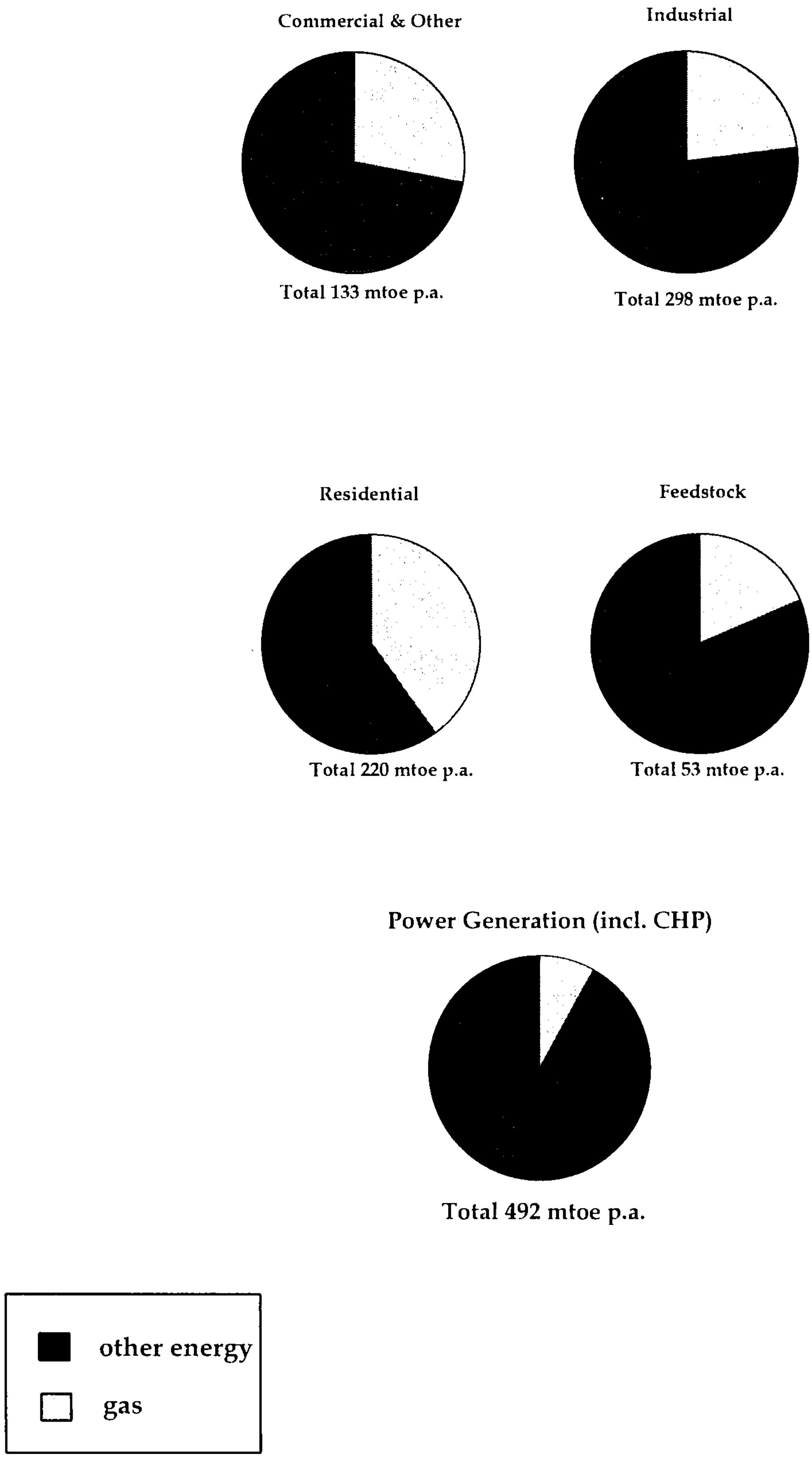
11.1. Sectoral composition of demand

Demand is determined by the competitive position of gas in the market, which is different in each market sector. Consequently, the sectoral composition of gas demand is important. We have adopted the standard classification of demand, which depends on the type of energy service provided and the competing fuels that can supply the same service:

(a) residential (competing fuels: electricity and gasoil);
(b) commercial (competing fuel: mainly gasoil);
(c) industrial (competing fuel: low sulphur fuel oil, and sometimes gasoil);
(d) feedstock (gas price set independently by world chemical markets);
(e) power generation (competing fuel: mainly coal, also oil and nuclear).

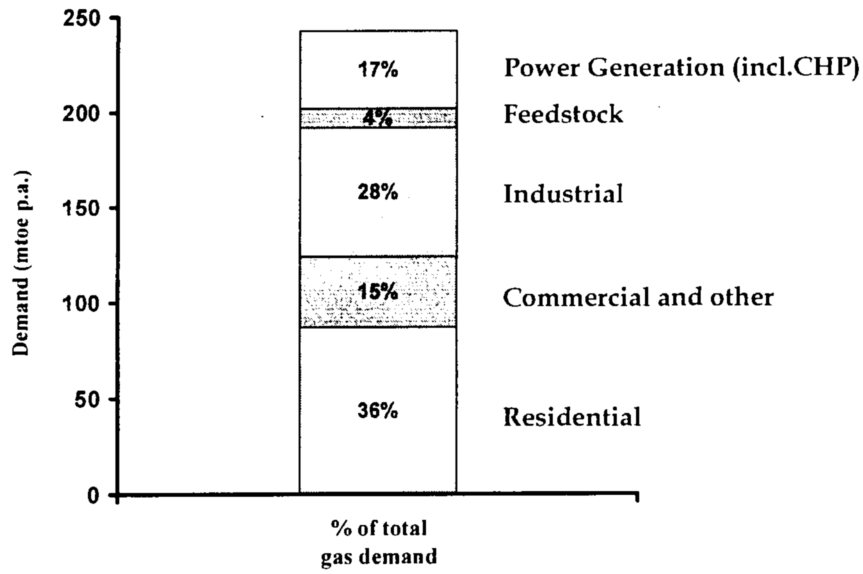
The demand for gas in each sector at present, and its market share, is shown in Figures 11.1 and 11.2. Table 11.1 defines the major competing fuels in each sector and summarizes the effect they have on the relationship between the potential price of gas and demand. There is considerable variation in the sectoral composition of demand between Member States, and this is shown in the Appendices.

Figure 11.1 Market share of gas in each sector



Source: IEA data for 1993 (EU-12).

Figure 11.2. Sectoral composition of gas demand



Source: IEA data for 1993 (EU-12).

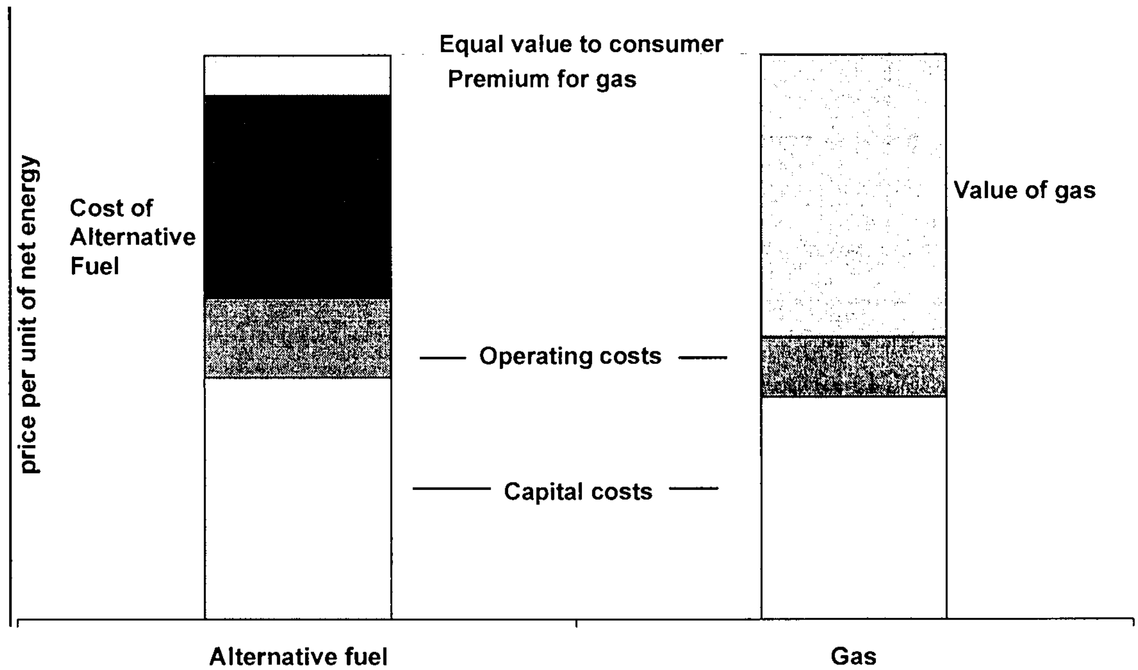
Table 11.1. Competing fuels and their effect on gas demand characteristics

	Typical uses	Principal competing fuels	Effect on price/quantity of competition with other fuels
Residential	Space heating, hot water, cooking	Gasoil, electricity	• Large installed base implies significant inertia • Gas has some convenience premium • Very high value against clectricity
Commercial	Space heating, hot water	Gasoil, electricity	• Large installed base implies significant inertia • Quality of energy service (cleanliness, security) generally more important than price
Industrial	Process heat, steam raising, hot water for processes (very large quantities)	Low sulphur fuel oil, gasoil, some coal	• Low sulphur fuels compete with gas (environmental regulation) • High gas value where gasoil competes • Gas has premium value in some industrial applications, little or no premium in others, especially steam raising and hot water applications • Larger users often dual fired, and able to switch readily between gas and oil
Power generation	Motive power for turbines	Coal, oil nuclear	• Higher efficiency and low capital costs of combined cycle leads to high gas value • Low gas value in conventional steam turbine plant (similar efficiency for different fuel types)

11.2. The market value of gas as an influence on demand

The availability of substitute fuels imposes a ceiling on the gas price. If the gas price rises above the total cost of using the alternative fuel, then gas will be uncompetitive, and consumer demand for gas will fall. This is the basis for the 'market value' or opportunity cost pricing of gas prevalent in much of Europe, where gas is priced in relation to oil products or other fuels such that the total costs of using two fuels are equivalent (see Figure 11.3). It is sometimes argued that this provides sufficient competition for gas, and prevents abuses of monopoly power. This argument is discussed further below, and calculations of gas value are presented in Chapter 13.

Figure 11.3. The market value of gas (illustrative)



11.3. Demand functions and price elasticity

The price elasticity of demand for gas is a key influence on the outcome of the scenarios for the completion of the single energy market, because it determines the way in which monopolistic or oligopolistic power will be exercised. If demand is price inelastic below the price of competing fuels, this may allow a monopolistic transmission company to increase profits by raising the price to just below that of parity with the competing fuel. The consequences of this are discussed further in the following sections.

We have estimated the demand functions for gas in the various sectors based on the competitive situation in each market segment. In each sector, demand decreases rapidly as the price approaches that of the competing fuels but is price inelastic below this point as no substitutes are readily available.[25] This is because in almost all cases consumers require energy services (space heating, steam raising, turbine power to generate electricity) rather than a particular fuel. Consequently, the demand for gas is derived from the overall demand for energy services, with the amount of gas required dependent mainly on whether it is competitive with the alternative fuels in providing the required service at lowest total cost. This implies that demand for gas will become highly elastic when its price is such that the total cost of providing the service approaches that of the competing fuel.

Schematic demand curves for each sector are shown in the Figure 11.4. They illustrate the following patterns:

(a) In the residential sector demand, the installed appliance base (and consequently high switching costs for existing consumers) leads to demand which is highly price inelastic except in the very long term or when the network is growing and consumers are making a choice of heating systems. For this reason, gas pricing is controlled by public policy in much of Europe (there is only indirect oversight in Germany).

(b) In the industrial sector demand is highly price elastic at or a little above a price of thermal parity with oil, and inelastic below this. Many consumers have dual fuel equipment and can switch between fuels readily.

(c) In the commercial sector, most consumers could use gasoil, but with much less propensity to switch in response to a small price incentive.

(d) In a competitive power sector, gas demand would be highly elastic at the price at which it reaches parity with the fully built up cost of new generation, and inelastic at lower prices. Demand becomes elastic again when the price falls to thermal parity with coal and oil, because it becomes economic to burn gas in steam turbines. A discount to the price of coal may be required to stimulate large-scale demand in the more conservative utility environment that applies in much of Europe at present.

Other drivers of gas demand are described in the Appendices. Empirical evidence on the price elasticity of gas demand is limited because pricing regimes have tended to be stable. That which is available supports the picture presented here. For example, residential gas demand in the UK has shown almost no increase in response to a 20% real terms price decrease in the last few years, and gas is typically priced at only a modest premium to oil in industry (see Appendix B). There may be some asymmetry in the elasticities in that demand may rise less in response to a price fall than it would decrease in response to a price increase.

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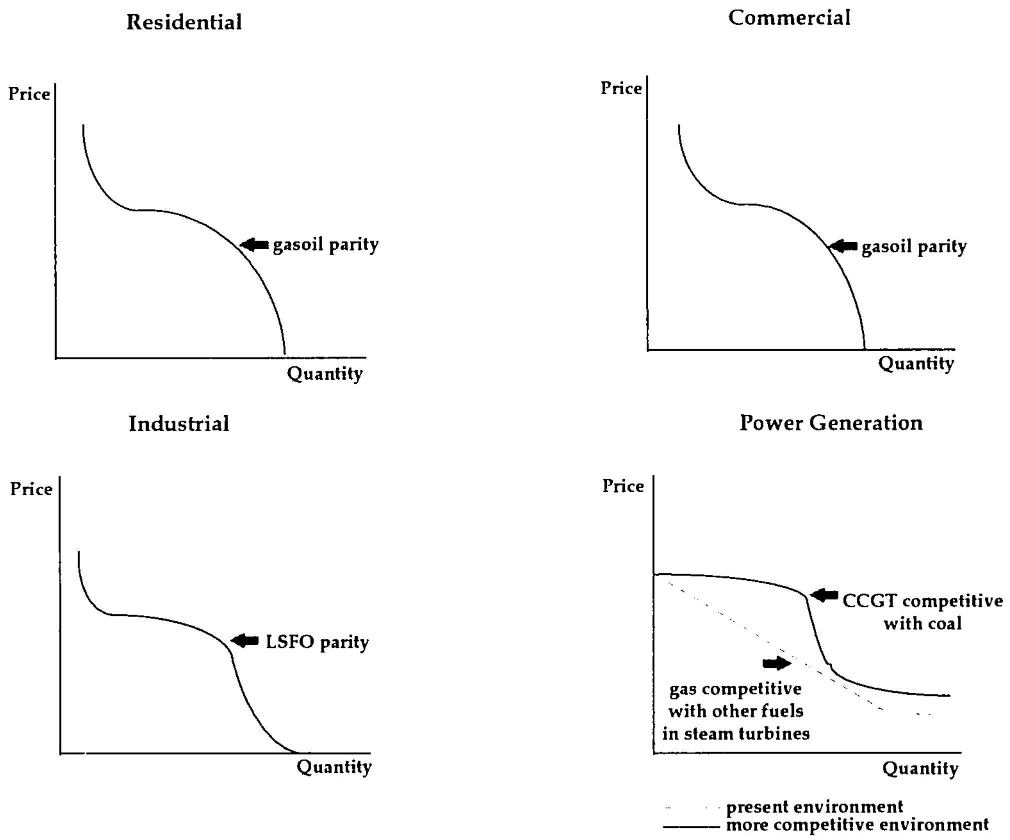
25 It should be noted that this is different from the kinked demand curve sometimes discussed in the literature on oligopoly, which makes assumptions about the production response of competing oligopolists. In this case the 'kink' is imposed by the price of competing fuels, which is set by world markets and is exogenous to the gas market.

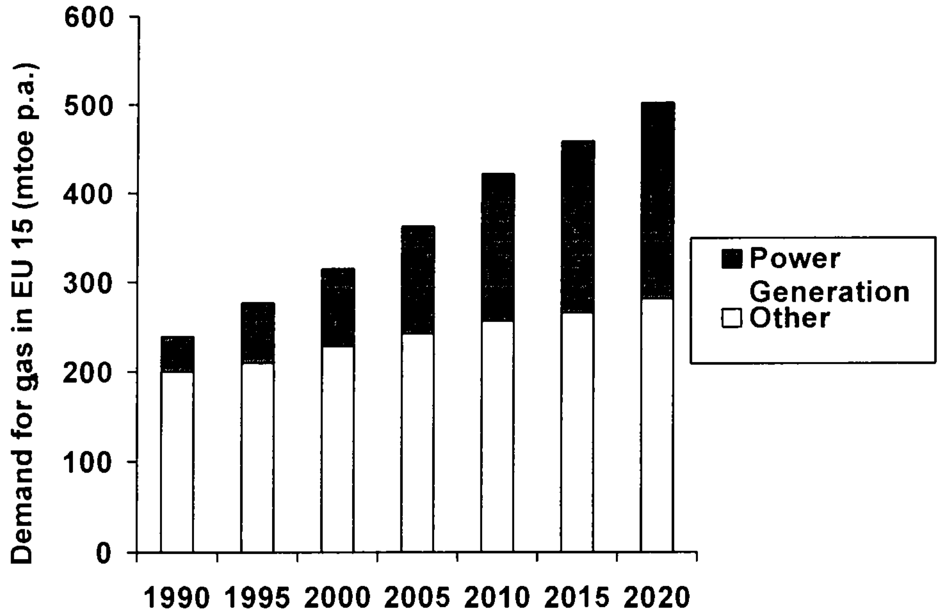
Figure 11.4. Schematic sectoral demand curves for gas



11.4. Demand forecasts

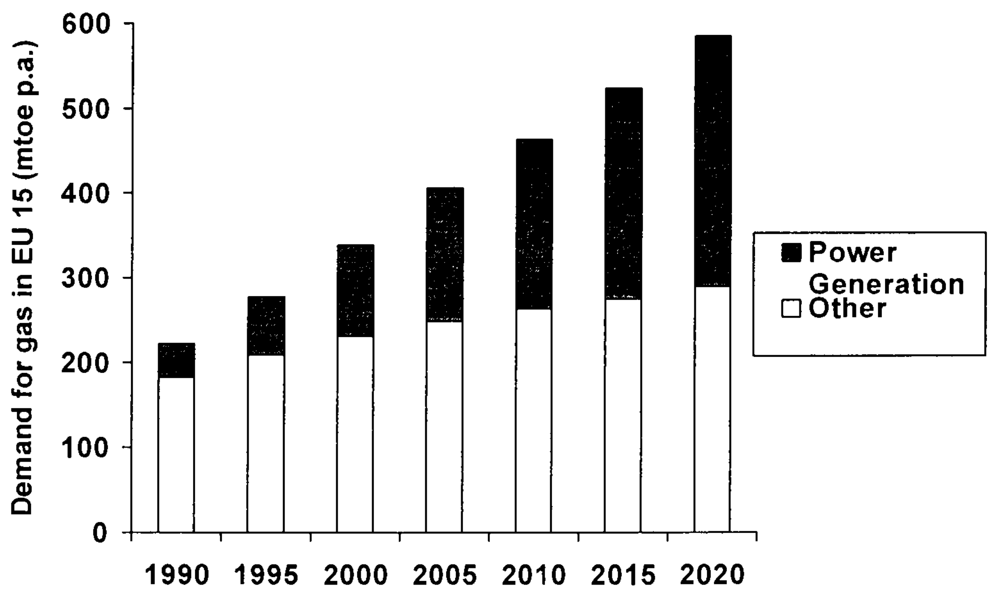
The effects of the completion of the single energy market will depend in part on the underlying demand for gas. The central demand forecast included here is shown in Figure 11.5. It is taken from the conventional wisdom scenario in the Energy Futures to 2020 study produced for the European Commission. It is in line with forecasts by others (see comparison of forecasts in Appendices). Provided gas demand continues to grow, the conclusions in this report are not sensitive to small variations in demand levels and are reinforced if demand growth is significantly greater than shown. By far the largest uncertainty in the demand forecast is the scale of growth in the power sector, which has the potential to be much greater than shown in the base case. An alternative scenario (the Hypermarket scenario) from the Energy Futures to 2020 study is shown in Figure 11.6 to illustrate the possibility of increased gas demand, especially in the power sector, in a more competitive market. This is discussed more fully in the section on electricity and in the scenarios presented here.

Figure 11.5. Base case gas demand forecast (conventional wisdom scenario)



Source: Energy Futures to 2020 study.

Figure 11.6. Alternative gas demand forecast (hypermarket scenario)



Source: Energy Futures to 2020 study.

11.5. Investment in storage

Demand growth over the next 25 years is likely to require some 30 bcm of additional storage capacity for load balancing and security of supply if present ratios of demand to storage capacity are maintained. The increase in long-distance supplies could increase the requirement for storage. However, a greater proportion of baseload demand from the power sector and increased use of interruptible contracts and dual fixing could greatly reduce this. Such a large amount of additional storage clearly poses a major challenge to the industry. Storage costs are very site specific, so generic costs are difficult to estimate, but at least ECU 10 billion or more of investment in additional storage facilities may be required.

12. Supply

This chapter describes the structure of the supply available to meet demand, and the implications of this for the single energy market. Unlike electricity, which is a manufactured good produced throughout the Community, gas is a natural resource found in only a limited number of locations. Furthermore, transport costs are high, leading to markets being regional in character. This is likely to continue to be the case, despite continuing reductions in the cost of transporting gas by sea as liquefied natural gas (LNG). This regional character of the gas market, which contrasts strongly with the global character of oil markets, has profound implications for the evolution of competition.

We consider supplies as being grouped into four categories:

(a) indigenous production to serve local markets,
(b) exports by countries within the EU,
(c) exports by countries outside the EU able to supply large quantities of gas,
(d) sources likely to provide small volumes of imports, mainly of LNG.

The potential role of each group of suppliers within the European gas market is now considered.

Figure 12.1 shows the conventional wisdom projection of demand presented in the previous section, matched with contracted imports from now to 2010. Existing import contracts are assumed to be extended, including maintenance of Dutch exports at present levels.[26] They show some 100 mtoe of demand uncontracted by 2010. Additionally, many existing import contracts will need to be renewed during this period, extending the proportion of the market for which the supply source is not yet committed.

The reserves in each of the main producers are very large (see Appendix B.3). For example, Norwegian reserves are 2,000 bcm, and Russian reserves are 48,100 bcm compared with present consumption in the EU of some 280 bcm p.a. (1 mtoe is equal to approximately 1.15 bcm). There is a tendency for new discoveries and reserve upgrades to replenish resources, and actual production is likely to be available for significantly longer than suggested by present reserve to production (r/p) ratios. Development of the market is therefore unlikely to be constrained by the availability of reserves within this period.

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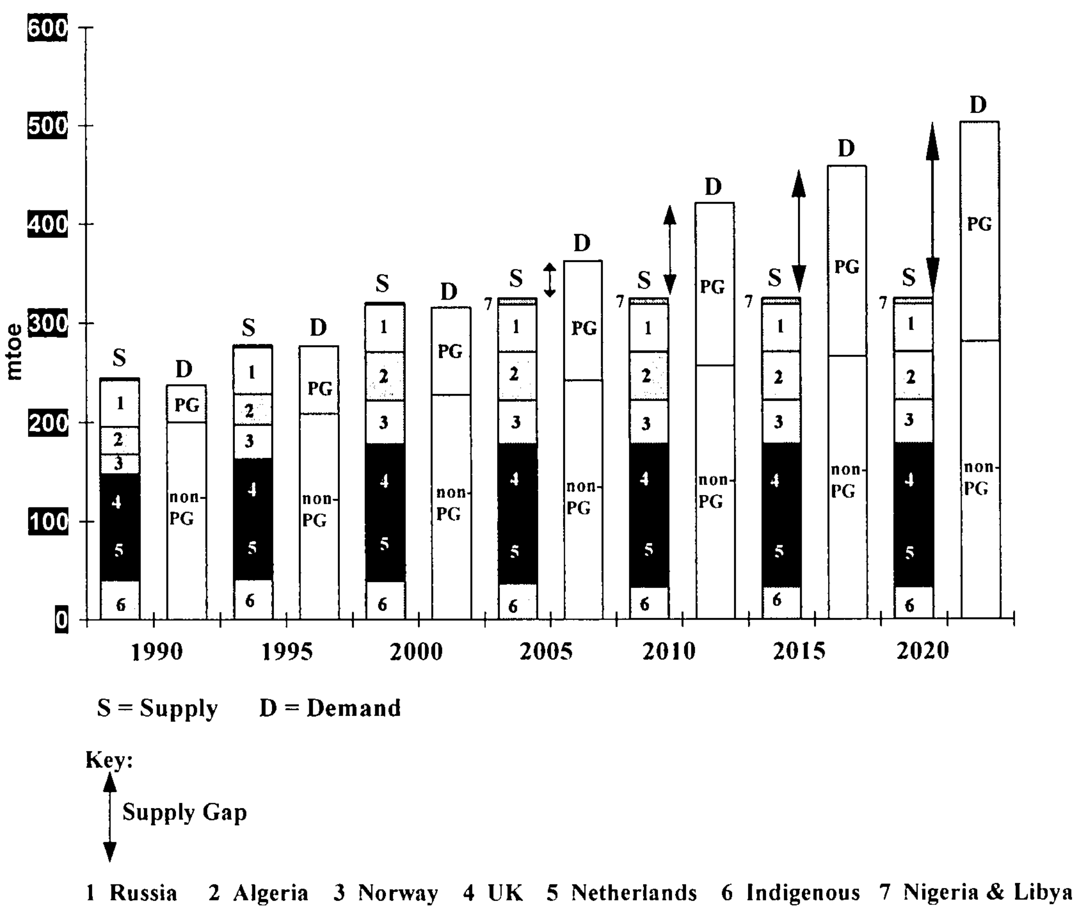
26 Availability of Dutch gas is assumed to be somewhat greater than in the Energy Futures to 2020 study, reflecting consistent previous upgrading of reserve estimates. If the lower assumption were adopted, that would reinforce the conclusions reached here.

Figure 12.1. Comparison of demand and contracted supply for the EU



12.1. Indigenous production

Production within the EU will be unable to meet significant incremental demand. Little increase in production is possible from Italy and Germany, the two largest producers after the UK and the Netherlands, and there is little production elsewhere. Large new discoveries are not expected. It is assumed for modelling purposes that indigenous gas will be produced first to ensure security of supply and facilitate load balancing. Production is assumed to decline very slowly from present levels.

12.2. EU exporters

The Netherlands has the potential to export large additional quantities of low cost gas in the short to medium term. Modelling of European supply based on cost minimization would suggest that such additional quantities would be produced. Increases in production from the Netherlands are technically feasible, but the Netherlands has a policy of not increasing exports significantly beyond their present levels to preserve long-term security of supply. Large-scale increases in exports from the large Groningen field would require significant long-term commitment as the gas is of a different composition ('L-Gas') from that burnt elsewhere in Europe ('H-Gas') and cannot mix in the same network. There are presently few signs of this policy changing to make large amounts of new gas available, although additional demand within the Netherlands is likely to be accommodated.

The United Kingdom will be able to provide some exports to Europe via the interconnector or other lines, but much of the available reserves will be required for indigenous UK use, in particular to meet the rapid demand growth from the power sector. In the longer term the UK is expected to resume net imports of gas because indigenous reserves will be insufficient to meet demand. The direction, magnitude and timing of flows along the interconnector are highly uncertain and treated as an exogenous variable for modelling purposes. They mainly affect the timing of additional imports from outside the EU rather than their necessity. The UK's present policy of favouring indigenous resources over imports is expected to continue.

12.3. Imports

Examination of cost data and reserve data (see Appendix B.3) implies that large incremental quantities of gas are available from three main sources: the former Soviet Union (FSU) (mainly Russia), Norway, and Algeria. Other sources outside the EU, such as Nigeria and Venezuela, are more distant, and will mainly deliver LNG. Consequently, these are only likely to provide small increments of supply (e.g. 5 bcm p.a. from each of two to three schemes by 2010) due to financing and logistical constraints, although in principle reserves are available to provide imports on a larger scale. A pipeline from Iran is viewed as a very long-term prospect in view of the political instability along the route, although the results of recent discussions with Turkey appear promising. A pipeline from Turkmenistan not under the control of Gazprom is also likely to take many years to realize. If independent supply from Turkmenistan or Iran were to be realized, these would form very useful additional sources of supply.

Each of the three main incremental suppliers is state controlled:

(a) Algeria has a single state-owned producer (Sonatrach). Two large developments have recently been signed involving foreign participants (BP and Total), which include some joint marketing, but overall control is expected to remain with Sonatrach. There is some political instability, but the effect on gas exports has so far been limited.
(b) Norway has a consortium of producers and marketers (the GFU) which is subject to significant government influence. For example, Saga's recent attempts to contract with Wintershall were refused permission. The main producer (Statoil) is state-owned.
(c) Exports from the FSU remain under the effective control of Gazprom. Those republics other than Russia which have significant gas reserves must, at present, largely use the Gazprom system.

All three of these suppliers will probably be required for diversity of supply reasons.

The main possibilities for further diversity appear to lie with exports from other FSU republics that are not dependent on Gazprom and lowering the cost of long-distance LNG imports and perhaps imports from Iran. The Nigerian LNG project may be a first indication of this.

For modelling purposes we have assumed small quantities of gas from other producers and other FSU republics being imported for diversity of supply reasons. These are treated as an exogenous variable. The three major exporters are then assumed to compete for the remaining market. The possibilities for encouraging more disparate sources of supply are considered further in the chapter on policy implications.

12.4. Costs of supply

There are wide variations in estimates of the costs of supply to the EU border. These estimates reflect differences in production cost estimates, the use of new versus existing capacity, financial parameters, and assumptions about the proportion and cost of local input.[27]

Table 12.1 summarizes the best available estimates for production and transport costs. They exclude transit fees, for crossing intermediate countries (e.g. Poland and Belarus), which are in effect a form of tax to extract economic rent. These are considered to be part of upstream rents. Upstream taxes are also excluded as these are also a means of extracting upstream rents.[28] Costs are tending to reduce in real terms as technology improves, especially for LNG. A comprehensive list of cost estimates is given in Appendix B.3. Costs are compared with market values for gas in the following chapter.

Table 12.1. Representative costs of incremental supply

	Cost to European border (US$/MMBtu)
Russia (Debottlenecks + expansion from existing production)	0.5–2.38
Algeria New	1.25–2.00
Russia New (Yamal)	2.73
Norway New (Haltenbanken)	3.25
Qatar LNG	3.51

Source: IEA.
Assumptions: Resource costs (i.e. excluding transport tariffs and upstream taxes but including costs of production and transport to the EU border); 10% discount rate. Breakdown shown in Appendices.

12.4.1. Load factor

The supply cost estimates shown assume baseload delivery. Delivery of gas at lower load factor becomes prohibitively expensive and additional storage close to low load factor demand (such as that from the residential sector) will be required as the proportion of demand met by imports increases. However, demand from the power sector and from large industrial consumers is likely to be baseload, and this assumption is adopted for the remainder of this chapter.

27 Estimates such as those shown are often combined to form a supply curve. However, this is potentially misleading if not interpreted with care, as volumes are in practice often potentially larger, especially from Russia.

28 The term 'upstream' in the oil and gas industry refers to exploration and production. 'Downstream' refers to the delivery of gas to the consumer.

12.5. The pipeline network

Figure 12.2 shows schematically the main sources of gas on the European gas pipelines grid. Each of the main demand centres is supplied by main transmission lines of large diameter, large capacity pipelines. There are pipelines running from the Netherlands to Germany, Belgium and Italy. Russian gas exports are delivered at the border of the Czech Republic with Germany, and are delivered from there to demand centres within Germany and France. Russian exports to Italy are routed via Austria. Norwegian gas lands at both Emden and Zeebrugge. Algerian gas flows by pipeline to Italy, and as LNG to various terminals on the European coast. A new pipeline will take gas from Algeria to Spain. A small capacity line links France and Spain.

Figure 12.2. Schematic representation of gas flows

12.5.1. Interconnection and completion of the single market

Until now, Portugal and Greece have lacked gas infrastructure and the UK system has been isolated from the continental European system. Links are now being established (see below). By far the most significant of these both in terms of volume and its effect on the market is the UK/Zeebrugge interconnector. This is also likely to require reinforcement of the transmission links from Zeebrugge to demand centres to which the gas will be delivered, especially Germany.

The demand figures shown in Chapter 11 assume the interconnection of those markets that have in the past been without gas (Greece and Portugal) proceeds, although demand from these markets is not large. The investments required to complete the integration, totalling some ECU 2.1 billion, are shown in Table 12.2. These projects are important in any circumstances, and are not dependent on liberalization of the market to proceed.

Table 12.2. New pipelines to complete trans-European networks

Project	Status	Required investment (million ECU)
Spain–Portugal (spur from GME Algeria–Spain)	Planned (GME due for completion this year)	390
Bulgaria to Greece	Under construction	1,280
UK to continental Europe	Financing complete, due to commence operation late 1998	550
Total		**2,220**

Source: European Commission.

In addition, there are several projects that increase the interconnectivity of the European network. For example, a new line from the Irish Republic to Northern Ireland would increase interconnectivity, but would not represent a fundamental change in the access of regions to the grid (because Northern Ireland is already linked to the main UK grid).

Other major new pipelines are likely to be mainly from the major importing countries to the EU border, with appropriate additional capacity within the EU. In particular, there will be large new pipelines from Russia, and maybe reinforcement of existing links from Algeria and Norway.

12.5.2. Effect of liberalization

The projects described are driven by fundamental supply and demand forces within the market, or by policy goals to increase integration. With the completion of the projects shown in Table 12.2, the main remaining isolated markets will have been connected. Additional links to increase interconnection may be judged to be desirable on policy grounds. For example, an increase in the capacity of the links from Spain to France may increase security of Spanish supply in the event of disruption of supply from Algeria. However, such policy judgements are outside the scope of this work, which refers specifically to completion of the single market.

Changes arising from the completion of the single market, i.e. those that arise from changes to the fundamental supply and demand forces within the market, are expected to be much less than for electricity, because the effect of liberalization on trade flows will be less. As described later in this report, the effect on demand is not likely to be large. The main effect on demand is likely to be if power projects are permitted by the removal of exclusivity rights. In addition, there may be some increase in interconnection to allow trades within the system, to increase the overall efficiency of the network, and perhaps to allow the producers to access the market more directly, as in the case of the Wintershall line. Supply changes will mainly be in the form of additional imports, with corresponding reinforcement of the grid within the EU. Changes in production within the EU are likely to be small, with the exception of short- to medium-term changes resulting from changes to flows along the UK/Zeebrugge interconnector.

From these considerations it seems likely that the effect of liberalization on integration will be small but positive, with the removal of exclusive rights to build pipelines the most important measure.

13. The value chain

This chapter describes how large monopoly rents can be present if there is not full gas-to-gas competition. The likelihood of such monopoly power being present and the nature of competition are discussed in the following sections.

13.1. Potential for monopoly rents

In Chapter 11, estimates showed demand for gas to be highly elastic above the price of competing fuels, and inelastic below this level. This creates the potential for monopoly rents. For example, a transmission company acting as a profit maximizing monopolist would choose to raise prices to just below parity with competing fuels because this would increase margins more than it would reduce volumes, so increasing total profits. A limited number of upstream suppliers able to exercise monopoly power would be expected to do the same. Conversely, in a fully competitive gas market with numerous suppliers, the suppliers would compete, and prices would fall to the marginal cost of the incremental supplier, as in a normal competitive market.

The magnitude of any potential monopoly rents can only be derived from a comparison of costs and values. If the price set by competition with other fuels is low compared with the cost of delivering the gas, then there will be no economic rent, because the ceiling imposed on the gas price by the ability to substitute other energy sources will ensure the absence of profits from monopoly control of the market. If the ceiling imposed by the oil price is above costs, then rents will be present. In the absence of effective gas-to-gas competition, rents may be appropriated by the parties in the production chain.

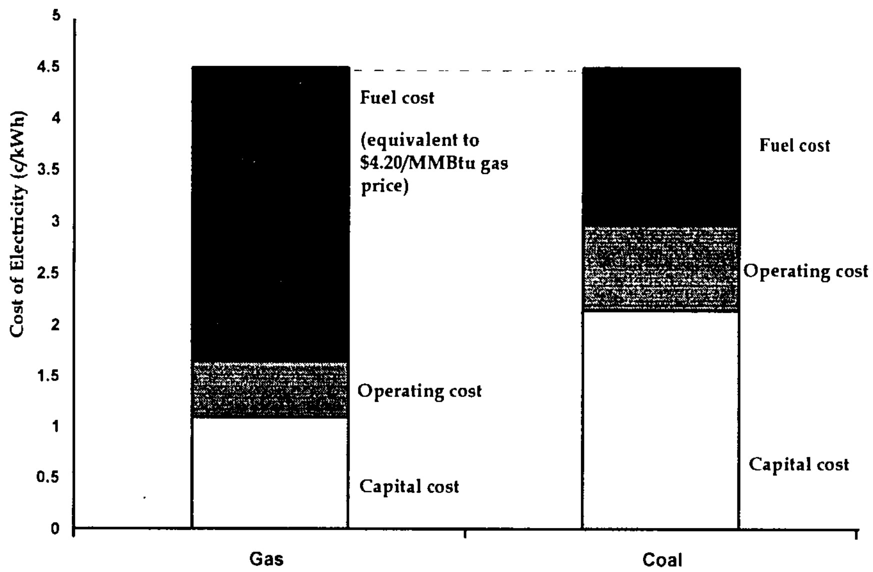
We have examined the value chain for gas. Figure 13.1 shows the value of gas in power generation[29] which is high. The clearest and best known example of a high price being paid for gas on this basis is the contract between the Dutch power producers association (SEP) and the Norwegian export consortium (GFU), for supply of the Eemshalven plant. This sector is the most likely to be affected by TPA because amounts consumed at each site are large. The assumption is that the price is set by the cost of the competing fuel (i.e. there is market value pricing and no gas-to-gas competition). This is equivalent to pricing just below the horizontal (highly elastic) section of the demand curves shown in Chapter 10 above. The price of competing fuel includes any taxes, and all taxes on gas are deducted from the calculated value. The calculations of the value of gas include the cost of FGD in power generation, and assume low sulphur oil products, and so include the environmental premium for gas as a low sulphur fuel. However, no premium for lower CO_2 emissions is included. If this were present (e.g. because of a carbon tax), the value of gas, and consequently the rents, would increase.

Table 13.1 compares these values with the cost of production and transmission to show available rents. They show the existence of substantial rents in the value chain, especially in the power sector. Rents in the industrial sector may be low or negative in some scenarios (in particular those in which the environment premium for gas was much lower, and gas is in

29 The comparison is with coal, which is the major competing fuel in most of Europe. Assumptions for coal (e.g. on thermal efficiency) are favourable. Comparison with fuel oil produces similar values. Comparison with nuclear plant produces higher values (see Appendices).

competition with high sulphur fuel oil, in which case demand would be likely to be restricted). However, competition with high sulphur fuel oil seems unlikely to be widespread in industry in the long term in view of emerging environmental regulation. In practice, rents in the power sector may be limited by competition from long-distance delivery of LNG, the cost of which may place an effective ceiling on the gas price.

Figure 13.1. Comparison of costs of generation



		Coal	Gas
Assumptions:	Efficiencies:	42%	55%
	Capital cost ($/kW)	1300	650

Discount rate = 10%, load factor = 85%, coal price = $50/tonne delivered to plant (6500kcal/kg)

Table 13.1. Rents available in the gas supply chain (US$/MMBtu)[1]

	Power generation	Industry[2]
Value of gas to consumer	4.20	3.50
Transmission (typical value)	0.30	0.30
Production + delivery to European border (new Russian gas)	2.73	2.73
Available rent	1.17	0.47

Source: LE estimates from IEA data.

[1] Costs and values both assume baseload supply.

[2] Thermal parity with low sulphur fuel oil is assumed with no premium and no allowance for industrial applications in which gas competes with gasoil, or where gas is the only realistic choice of fuel.

13.2. Gas prices

At present, there is a wide variation of gas prices in Europe. This reflects different pricing principles ('cost plus' versus 'market value'), and differences in the price of competing fuels. There are also some variations in costs, especially for the residential sector, due to differences in the density of the network and average load factor and levels of consumption.

14. Competition and industry structure

This chapter reviews the aspects of industry structure which determine the competitiveness of the gas market, and so will affect the consequences of measures designed to complete the single energy market. The degree of competitiveness largely reflects the degree of monopoly power in the market, and the scope for reducing the potential for monopolistic pricing by introducing TPA and related measures.

Large economies of scale lead to natural monopolies or oligopolies in transmission and distribution. These are often supported by legal monopoly rights. In the present industry structure it is therefore possible for transmission companies to act as monopolists, setting price at above the competitive level to gain additional profits, unless they are prevented from doing so by other means, e.g. regulation.

Creating the right of TPA to the system is designed to break this monopoly power. By granting consumers access to independent suppliers, each consumer has a choice of sources for gas, and price competition would be expected to emerge. The cost of transmission would become like any other of the supplier's costs, and may be either fixed (in a full TPA scenario), or subject to negotiation (in an nTPA scenario). This is the situation which has emerged for large consumers in the UK gas market, with numerous North Sea producers and independent supply companies competing to provide consumers with gas via British Gas's pipeline system.

The key issue is whether a similar situation is likely to emerge in continental Europe. The monopoly price setting power of the transmission company is likely to be partly or wholly removed by TPA. However, with a limited number of suppliers able to provide sufficient volumes to meet incremental demand, it may be that the monopoly power of the transmission company is replaced by an oligopoly of producers who do not engage in price competition. Assessment of this possibility is a major focus of the modelling work.

The strong elements of monopoly present until now in both the upstream (production) and downstream (transmission and distribution) has led to a prevalence of long-term contracts between parties to allocate risks and reduce exposure to future actions by the other party. This is likely to affect the form of evolution to competition. In addition, the structure of the commercial relationships in the industry has led to a lack of transparency, which may further hinder the evolution of a fully functioning market.

The natural monopoly nature of transmission, the commercial structure of the industry, the existence of long-term contracts, and the lack of transparency are now each reviewed in more detail.

14.1. Economies of scale in transmission

The economies of scale in gas transmission are very large. The cost of moving a cubic metre (m^3) of gas via a large diameter line is a small fraction of the cost of transmission via a small diameter line, because capacity increases with diameter vary much more rapidly than cost. A large diameter pipeline giving the greatest economies of scale will typically have a capacity of 15 to 20 bcm or more, commensurate with the entire consumption of a small market (e.g. Belgium at 9 bcm p.a.), or a significant proportion of a large market (e.g. 25% of the German market of 65 bcm). Consequently, gas transmission is a classic natural monopoly or oligopoly, with the size of a single producing unit commensurate with the size of the market.

The existence of these large economies of scale is the major driver behind the introduction of TPA. A market may be served by only a small number of large import lines, and will therefore tend to be naturally oligopolistic in character, because the construction of a large number of competing pipelines (unhindered market entry) is not a realistic option. TPA therefore forms the only practical way of introducing widespread competition in gas supply, and the provision of transmission services will remain monopolistic or oligopolistic.

The scale of pipelines also has important implications for imports. A very large line is required if long-distance transmission is to be economic. Individual import schemes are therefore typically a large proportion of markets. For example, the new pipeline from Algeria to Spain will provide sufficient gas for the entire Spanish market for the foreseeable future. This furthers the tendency towards oligopoly.

In some cases competing lines will be built. The most significant example to date is the Wintershall line in Germany, which has led to competition and reductions in price close to the line. The behaviour of a market in such situations of effective duopoly is likely to be specific to the circumstances of the particular market. In many cases there is little or no effective competition, and the presence of natural monopoly has led to the need for widespread government regulation of gas utilities, and frequently state or municipal ownership has been the means chosen to attempt to ensure that the interests of the consumer are protected.

14.2. Separation of production and networks

The industry is not traditionally vertically integrated. Producers and transmission companies are usually separate entities with distinct ownership. Imports from outside the EU have been governed by long-term contracts between transmission companies and the producers. There has also been a separation in the UK between the transmission company (BG) and the producers. The major exceptions to this pattern of separation are in the Netherlands, where production (NAM) and transmission (Gasunie) have a degree of common ownership, some common ownership in Germany, and the state ownership of both upstream (Agip) and transmission (SNAM) in Italy.

This existing vertical separation avoids the need for enforcement of separation by regulation. In some respects, this may ease the transition to alternative market structures. However, at each vertical stage of the chain there is a limited number of players. Each major European market has a single dominant transmission company. Germany is a partial exception to this but Ruhrgas retain significant influence over the market, and other transmission companies (Thyssengas, BEB, etc.) usually dominate their particular regional markets. This implies that there will be a large element of monopoly power in this section of the chain, corresponding to the natural monopoly character of the physical assets. As noted above, it is this problem that TPA is designed to address. In addition, the large amount of state control and influence over the upstream, noted in Chapter 12 above, means that there tend to be a few dominant players in this sector. Consequently, although the chain is not vertically integrated neither the upstream nor transmission has the multiplicity of competitors necessary for a classically competitive market to emerge.

14.3. Existence of long-term contracts

Unlike other commodities, such as oil or wheat, gas transport facilities (long distance pipelines) cannot be moved to serve other markets. A large investment is therefore tied to a particular market. In such circumstances, long-term contracts are often desired and are likely to persist as long as large capital assets must be dedicated to serving only one buyer, or taking gas from only one seller. This reflects legitimate economic considerations connected with risk reduction, and is traditional industry practice. The existence of such contracts can substantially slow the transition to alternative market structures as they will persist, locking in a substantial proportion of the market, even after TPA has been introduced. Further measures may be considered to address this. For example, in the UK a programme of forced release of gas was instituted by the regulator when the existence of long-term gas contracts slowed the introduction of competition.

14.4. Imperfect information and price discrimination

The gas industry is characterized by a lack of transparency of prices and costs. This affects the negotiating position of each party and therefore the prices at each point in the chain. Much data is uncertain to other players in the market:

(a) the precise value of gas to an individual consumer versus the alternative fuel,
(b) the transmission company's costs,
(c) the producer's costs,
(d) available capacities.

The degree of uncertainty on these will affect the negotiating position of each party. For example, compulsory rather than negotiated TPA will remove uncertainty on grid access charges. Regulatory oversight of charges should also, over time, lead prices to become more closely related to costs.

In addition to uncertainties in production and pipeline pricing and costs, there may exist opportunities for sellers to discriminate in setting prices to different consumers even if the costs of serving them are similar. For example:

(a) a transmission company may negotiate individually with large consumers and charge different prices. This is presently the case in Germany;
(b) a producer may do the same under a TPA regime in the absence of full upstream competition;
(c) a transmission company may negotiate separate access prices in an nTPA regime.

The greater the transparency of prices to consumers and for grid access, the smaller will be the opportunities for such discrimination.

Producers may price discriminate indirectly by charging a price to transmission companies which reflects the mix of consumers the transmission company serves. Such reasoning is reflected in the mixed fuel oil/gasoil indexation found in some import contracts at present. However, such discrimination is likely to be less effective than if the producer is able to sell directly to different classes of consumer under a TPA regime. For the purposes of modelling we have assumed that producers tend to treat each sector (residential, industrial etc.) as a separate market, seeking to maximize profit in each. Their bargaining power in this respect varies between scenarios.

14.5. Perceived risk of supply interruption

Risk of a major supply interruption is a major concern for all gas systems. The usual concerns about loss of revenue that apply to any commercial operation are compounded by concerns about safety, by the social importance of gas supply, and by the broader economic consequences of any interruption. Furthermore, the nature of gas infrastructure means that it is not possible to substitute one supply source for another rapidly.

These considerations mean that providers of gas to consumers will be unwilling to rely on a single supply source, and will seek diversity of supply. This strengthens the tendency for each major supplier to find some place in the market, and in particular limits the ability of Russia to compete market share away from other producers on price alone. It has also led to a desire to see LNG schemes which, although small relative to the market as a whole, are perceived as providing useful supply diversity.

There are also differences in perceived risk of interruptions by producers. In particular, Norway's political stability gives Norwegian producers a unique position among major imports to the EU.

14.6. Need for regulation

Under any structure for the gas industry, there will be a continuous need for regulation beyond matters of health, safety and environmental protection. This need arises from the natural monopoly characteristics of gas networks, which require either monitoring of access prices, or monitoring of gas prices to consumers. The monitoring of prices may range from direct control to general oversight to ensure that monopoly powers are not being abused (as in Germany). In any case, the wider importance of gas supply referred to above is likely to ensure that some continuing regulatory attention to the gas industry will continue.

15. Scenarios

In line with the terms of reference, we have examined three scenarios for the completion of the single energy market. The scenarios are chosen to be broadly consistent with those for electricity. The general nature of the reform envisaged is the same as for electricity, although details clearly differ because of the differences between the industries. As with electricity, factors not relating to market reform are kept constant between the three scenarios so that the effects of market reform can be described separately. The three scenarios are:

(a) *Business as usual:* a continuation of the present situation. This represents a continuation of the situation described in the preceding sections. This may include some increase in competition if competing pipelines are built and producers integrate downstream. However, there is assumed to be little effective competition, with transmission companies able to pass through all costs to customers, including their own gas purchase costs.

(b) *Negotiated TPA:* this includes the removal of restrictions on third party pipelines. Under this scenario the ability to build competing pipelines puts a fundamental limit on the amount which transmission companies can charge for access, because above a certain price it will be cheaper to build an alternative pipeline. This price will be high for small volumes because of the large economies of scale in transmission. However, short pipelines to consumers close to borders, or new lines able to transport large volumes (e.g. serving a group of power plants) may be economic. Negotiated TPA is also likely to impose direct limits on the price of access to the grid. The potential for arbitration appears likely to lead to broad pricing principles and to limits on access charges emerging. However, some price discrimination by the transmission company between parties seeking access to the grid is likely to remain in the absence of full price transparency. There is unlikely to be significant pressure on transmission companies' costs.

(c) *Compulsory TPA:* this is likely to have similar effects to negotiated TPA. In addition, price transparency is likely to remove the potential for access price discrimination by the transmission company and external regulation of access prices is likely to put long-term pressure on the transmission company to reduce costs. This is likely to lead to:
    (i) a weakening of the bargaining power of transmission companies compared with negotiated TPA;
    (ii) a loss of implicit rents presently appropriated by the transmission companies.

For modelling purposes we have sought to capture both of these effects as a loss of implicit rents presently appropriated by the transmission company in the form of a higher cost base and lack of pressure on returns (Figure 15.1).

15.1. Roles of market participants

The business as usual scenario with a continuation of the current industry structure is characterized as follows:

(a) gas producers outside the EU sell gas to transmission companies at the borders of the EU;
(b) transmission companies act as gas merchants between producers and consumers, and provide gas transportation services.

Under the TPA or nTPA scenarios, the structure of the market would be changed so that:

(a) gas producers would have the ability to sell gas to a proportion of the final market within the EU;
(b) transmission companies would provide transportation of gas from EU border to final market, and continue to provide their merchant function for those consumers who do not buy directly from producers.

Consequently, in the current structure, gas transmission companies fulfil two roles: that of merchant of gas for the final market, and that of a transporter of gas. Under TPA, transmission companies are only transporters of gas for the portion of the market that buys gas directly from producers, but retain their merchant function for the remainder of the market.

15.2. Effect of scenarios

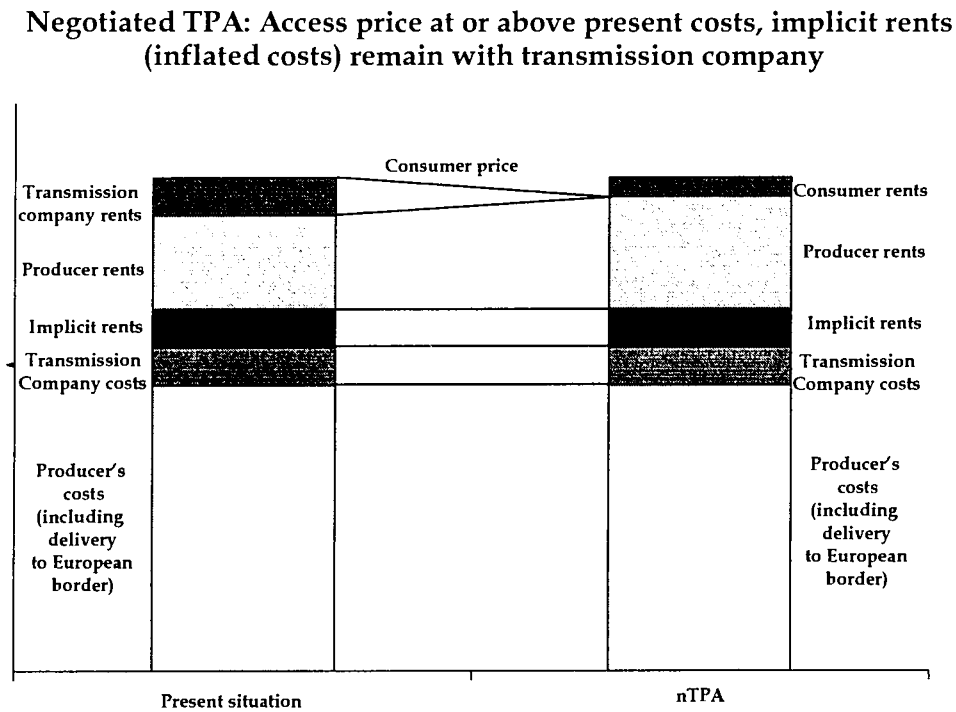
Figure 15.1 illustrates the effect of introducing TPA. At present the consumer price, fixed by the price of competing fuels, allows revenues that comprise the following:

(a) costs of production including delivery to the European border,
(b) costs of transmission,
(c) implicit rents earned by the transmission company as inflated costs etc.,
(d) rents accruing to the producer,
(e) rents accruing to the transmission company.

Under nTPA, the transmission company is assumed to maintain its implicit rents. The other rents it presently earns are assumed to be divided between the producer and the consumer. The reallocation of rents to the consumer is manifest as a price reduction. The case illustrated here supposes that the consumer is able to gain less rent than the transmission company. The opposite case, which would show larger price reductions, is discussed in the next chapter.

Under TPA, price transparency and pressure on costs also removes transmission companies' implicit rents. These are again allocated between consumers and producers, as are the other rents. Consumers and producers therefore gain more than under nTPA.

Figure 15.1. Negotiated TPA (illustrative)

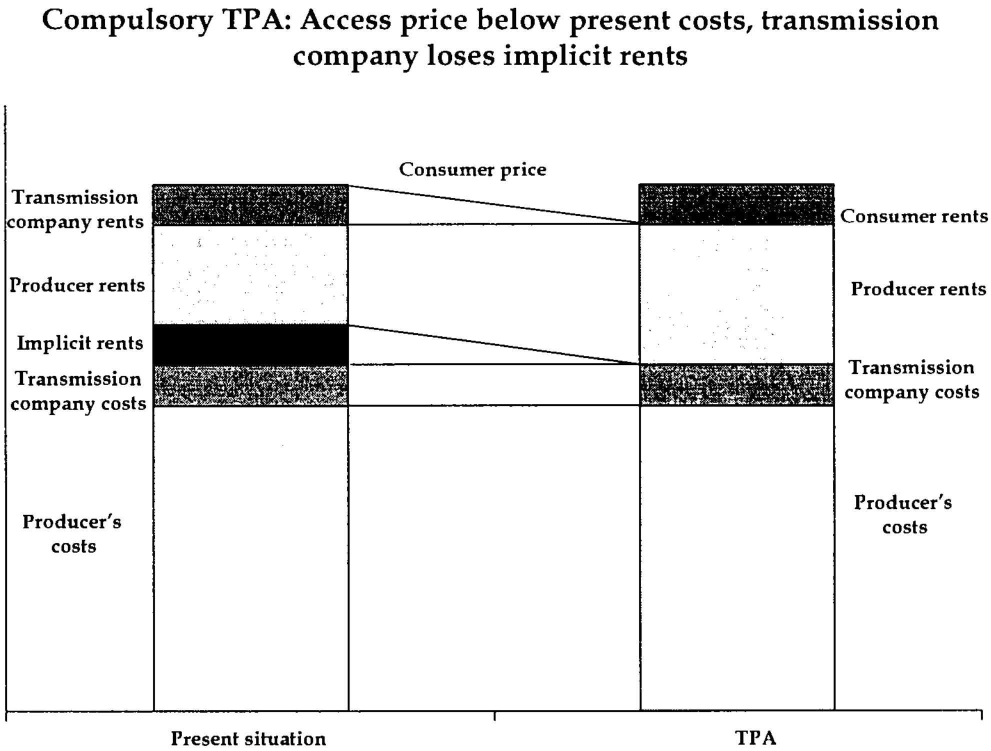


Note: For illustration it is assumed that transmission companies are able to appropriate more rents than consumers. This issue is discussed fully in the modelling work.

Notes:

(a) producer's costs unchanged.
(b) transmission company costs unchanged.
(c) implicit rents unchanged (stay with transmission company).
(d) market value of gas (total height of bar) remains unchanged.
(e) transmission company rents allocated between consumers and producers.

Figure 15.2. Compulsory TPA (illustrative)



Notes:

(a) producer's costs unchanged.

(b) transmission company costs unchanged.

(c) market value of gas (total height of bar) remains unchanged.

(d) transmission company rents (explicit and implicit) are allocated between consumers and producers.

16. Modelling structure

16.1. Modelling framework

The European gas industry has a number of distinctive characteristics which make the application of conventional equilibrium economics problematic. In particular, the persistence of oligopoly for the foreseeable future implies that models based on perfectly competitive markets will have limited applicability. In addition, rents are likely to be present among the oligopolists.

To address the problem we have adopted a two-stage conceptual approach (Figure 16.1). The first stage seeks to determine if producers compete. We have analysed this as a repeated bidding game in which each producer makes an offer to a buyer (transmission company, large industrial consumer, etc.) who has a well defined demand. One consequence of this may be that producers tend not to compete on price, but seek to price at full market value, with each getting a share of the market because of requirements for diversity of supply, etc. [30]

We then examine the consequences of this for an individual deal. If producers are not competing with each other on price, the problem becomes one of bargaining between a producer and the buyer. If the buyer is a customer under a negotiated TPA scenario, then the transmission company will also be a party to the bargaining. The bargaining is over the division of rents between the parties.

Clearly, the representation of pricing as a two-stage process is a simplification, as each stage will influence the other. For example, the producers' bargaining position may be influenced by any desire to maintain co-operation on price and so may, from the consumers' view, be in effect simultaneous bargains with implicitly co-operating producers. Similarly, the outcome of bargaining processes will affect other producers' position on sustainable prices: concessions to customers must be small enough to avoid destroying co-operation. However the model remains consistent provided that bargaining by customers is not sufficiently strong to induce a breakdown of co-operation on price. The consequences for increased price competition are reviewed below.

The assumptions, qualifications, and complications of the argument are described more fully in the Appendices. However, we do not consider the assumptions here to be any more restrictive than those necessary for other modelling approaches, and in many cases they are considerably closer to reality.[31] The main purpose is not to derive a fully realistic model (which is in any case an impossibility) but to use the modelling framework to inform the analysis of market dynamics.

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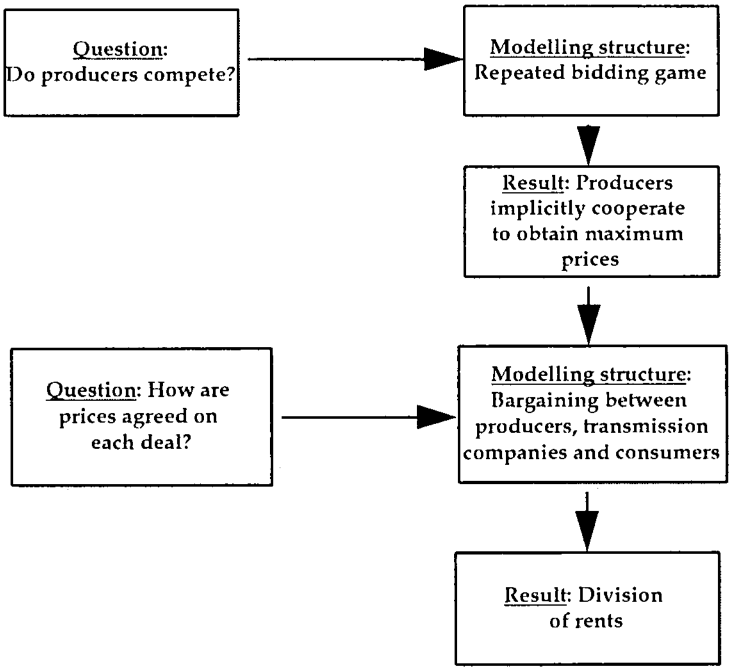
30 In this sense the model is dynamic, in that it recognizes the importance of the evolution of behaviour through time. However, it remains distinct from more traditional approaches which treat aggregated quantities and continuous variables that change through time according to a set of differential equations. For the reasons stated we believe the approach adopted here yields more insight.

31 We have considered, among other frameworks, Hotelling pricing (see Appendices), but do not consider this yields especially useful results in the context of the European gas industry.

Figure 16.1. Two-stage conceptual modelling approach



16.1.1. A repeated game and the emergence of spontaneous co-operation among producers

We have modelled the interaction of the three major incremental suppliers as a series of discrete bids where each producer attempts to secure the business of a particular buyer by making an offer of gas at a certain price. The quantity the buyer requires is assumed not to vary significantly with the price offered, because of the price inelastic nature of demand. The buyers are transmission companies acting in their merchant role in the business as usual scenario, and also power plants, large industrial consumers and distribution companies under a TPA environment. The producers make offers to each buyer for the first period, contracts are signed (which may extend beyond a year). The process is then repeated in subsequent years. This is illustrated schematically in Figure 16.2.

Each producer will develop a bidding strategy. The extremes will be to price at the full market value of the gas (set by the cost of using the competing fuel) and to price at the marginal cost of supply. There will be an almost infinite range of strategies in between.

This process has the 'Prisoners' Dilemma' reward structure common to price wars.[32] The optimal outcome for the producers is that they each bid in at the monopoly price with each getting a share of the market. However, on any individual set of bids there will be an incentive for a producer to offer a low price to undercut the competition. If this happens it may lead to a price war with all parties worse off.

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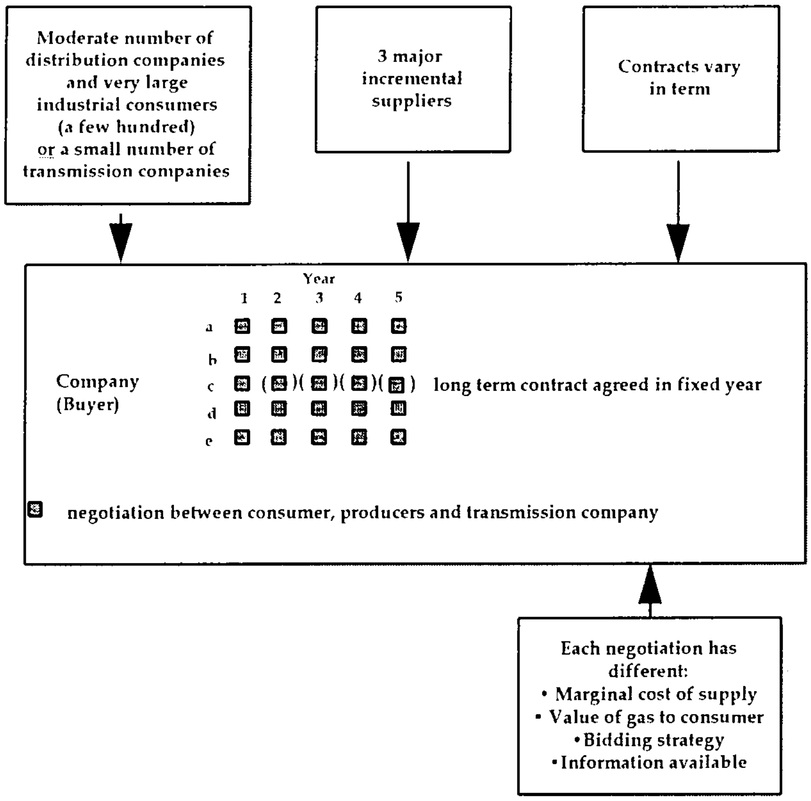
32 See Appendix B6.3 for a description of the Prisoners' Dilemma.

Figure 16.2. Modelling of the market



If there were a single set of bids, this would be likely to lead to competition with prices competed down to marginal cost. However, the existence of a number of customers and the fact that the contracts with customers would be renewed regularly, probably annually, produces a repeated process.

There has been a good deal of academic work on repeated games with a Prisoners' Dilemma structure (see Appendices). There are usually no methods for deriving an optimal bidding strategy in such circumstances, and computer based experiments have tended to be the preferred method of study. The studies each adopt somewhat different assumptions, but all show a strong tendency for co-operation to emerge spontaneously, and suggest that in a repeated game co-operation is likely to be the dominant strategy.

Most of the work in this area refers to repeated two-player games. As the number of players increases, the pressure to make price cuts will be stronger. With a sufficiently large number of players bidding in, as is the case in the US and the UK, full competition would be likely. However, implicit co-operation is likely to persist with only three players, especially as they have somewhat different positions in the market.

The presumption is that producers are able to avoid a mutually destructive price war by implicit co-operation, even if explicit co-operation is not possible. This appears to be entirely consistent with the present situation, with gas priced close with parity to competing fuels in most of Europe, and border prices reflecting a netback from this. This analysis suggests that it is a fundamental property of the existence of an upstream oligopoly, rather than a feature of the existence of local monopolies in gas transport. It may be expected to persist under TPA.[33]

16.1.2. Likelihood of a collusive outcome being realized in practice

The likelihood of a collusive outcome will depend on the incentives to collude and defect. There are strong incentives to collude if the product is homogeneous, and if the market would be competitive enough in the absence of collusion for prices to be forced down significantly. Incentives towards a non-collusive outcome include the possibility of gaining market share, and the likelihood of escaping retaliation. The main conditions for maintaining implicit price co-operation in a market are:

(a) repeated game with no clear termination point,
(b) few firms involved,
(c) prices visible,
(d) the potential for retaliation for price cuts must exist,
(e) possibilities for entry must be limited,
(f) limited gains from cutting prices in terms of increased market share.

All of these apply very strongly to the European gas industry. The only partial exception is the visibility of prices (which affects the ability of other players to determine if a competitor is undercutting their prices). However, prices are now more transparent than they were as a result of the Commission's Directive on transparency (OJ L 185, 17.7.1990). In addition, the nature of the gas industry is such that, even though prices are not published, general price levels are widely known amongst interested parties. We therefore conclude that the European gas industry may show tendencies towards collusive behaviour. This appears to be supported by the present level of border prices which is quite uniform (typically US$ 2.70–2.80/ MMBtu) and apparently above marginal costs of production.

It should be noted that the collusion referred to here does not refer to explicit agreements or any formal cartel. No European gas equivalent of OPEC is envisaged. The collusion is assumed to be entirely tacit, with the players remaining independent. The political and economic diversity of the exporters makes formal collusion highly unlikely. It may also reduce the potential for implicit collusion (see below).

16.1.3. Soundness of this conclusion from comparison with other industries

Comparisons can be made with other industries, such as telecommunications and airlines which have elements of natural monopoly or oligopoly, but where formal collusion may be excluded. Such comparisons show that when there are two or three players competing in a homogeneous market the characteristics of the market tend to be consistent with implicit collusion (although clearly implicit collusion is of its nature very difficult to prove). In these

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33 The issue of the finite nature of the resource base is also important. However, as noted in the discussion in the Appendix on Hotelling pricing the reserve base is sufficiently large (and robust due to new discoveries and reserve reappraisals) that it is unlikely to form a practical element of decision making for the major exporters. In any case, if the resource is finite, it serves to increase the incentives for producers to extract maximum rents, rather than engage in price competition to increase production of a (declining) resource.

markets there is little price competition, little difference between the product on offer, and comfortable margins. When a larger number of players is introduced (for example six) and the product is less homogeneous (e.g. different areas of coverage for portable telephones), the apparent level of competition in the market is higher.

One of the closest analogies to the repeated bidding process described here is the electricity pool in England and Wales, where two companies (National Power and PowerGen) dominate price setting.[34] Generating plant is bid into the system for each half hour during the day. This produces a market in which bids can vary each day, in which prices are highly visible, there is the possibility of retaliation, limited potential for entry into the relevant portion of the market (new plant goes into baseload) and limited potential to increase market share. On the criteria described above implicit collusion would therefore be expected. Market power is indeed now widely acknowledged to exist. Over the last two years prices have been held steady or forced down in the competitive (baseload) section of the market but have risen in the midload section of the pool, dominated by National Power and PowerGen.

Perceived market power by the main generators led the regulator to impose a price cap in 1994 and to require the two main generators to dispose of 6 GW of generating plant, with the objective of increasing competition (such regulatory intervention against the main incremental gas suppliers to Europe is, of course, much more difficult, as they are outside EU jurisdiction). This 6 GW is now to be sold to Eastern Group, increasing the number of major players from two to three. It is too early to determine the effect of the sale, but the price Eastern have paid for the assets implies they do not expect prices to be reduced significantly from their previous levels. This suggests a continuation of implicit price collusion with three main participants in the market.

16.2. Bargaining theory

Having defined the price that the producer will seek to offer in each bidding round, the question then becomes how price is actually agreed with the customer in each bidding round. The analysis above shows a strong tendency for the market price to lie just below the price of competing fuels, as at present. Demand would correspond to this. If price, volume and costs are largely fixed by the characteristics of the market, then there will be a fixed amount of rent to be bargained for and divided among the players.

This is a well defined problem in game theory.[35] Under certain assumptions, which are not restrictive, there is a unique solution determined by:

(a) *The number of players:* the greater the number of players, the more there are among which to divide the available rent, and so the less each receives.
(b) *Bargaining power:* the greater the bargaining power of a player, the greater the proportion of the rent they receive.
(c) *Risk averseness:* the greater a participant's risk averseness, the less their utility may be increased by providing extra funds, and the less they will receive. Their wish not to see

[34] A third player, pumped storage facilities owned by Mission Energy, also sets price some of the time.

[35] The treatment here is the Nash bargaining solution for the problem in which two or more players must agree on how to divide a fixed sum of money between them. This is described more fully in Appendix A.7, together with alternative approaches based on backward induction.

negotiation break down exceeds their additional utility at a lower level of monetary gain than if they are risk neutral.

The possibility of implicit collusion between producers occurs irrespective of whether consumers have access to pipeline capacity. It may be present either in the present industry circumstances, or under various forms of TPA. The key issue is the extent to which the alternative downstream market structures allow producers to benefit from potential collusion.

16.2.1. Modelling of bargaining power and risk averseness

Bargaining powers are relative, being expressed as a ratio of the bargaining power of two market participants (for convenience). The bargaining power and the risk averseness of the production companies are considered fixed between the scenarios and form a reference point against which the relative bargaining power of the transmission companies and customers is assessed.

The behaviour of transmission companies may be interpreted by assuming that they are 'satisficing', i.e. that they will seek to satisfy each of their constituencies, but will not maximize their performance against a single criteria. Under this model a transmission company would seek to:

(a) give adequate returns to shareholders,
(b) reward employees adequately and avoid redundancies,
(c) avoid attracting undue regulatory or government interference.

This set of objectives would suggest a bargaining position which would be satisfied by gaining modest rents. This view is broadly consistent with that taken by observers of the European gas business that transmission companies only seek and obtain modest rents, with the majority accruing to the producer. Such preferences would be manifest in rapidly declining marginal utilities for additional rents, which would result in lower risk tolerance.

Prima facie it seems reasonable to suppose that customers will be even more risk averse than transmission companies to a breakdown of negotiation. Energy costs are usually often only a small part of an industry's costs and residential consumers put a high premium on reliable supply. However, energy intensive industries may be relatively non-risk-averse: energy is a large proportion of costs, so any reduction in price increases their profits significantly, and may be necessary to ensure their survival in some instances. In contrast, the transmission company may gain limited benefits from increased rent. The risk averseness of power companies will depend on their circumstances. If they have guaranteed markets, they may react like distribution companies, with a high degree of risk averseness, but in a competitive market they may act more like a transmission company or energy intensive consumer, and so be more risk neutral.

It seems reasonable to suppose that the bargaining power of transmission companies would be greater than that of customers. They have the buying power that comes from being a large customer. However, it is also possible that customers will be more aggressive in negotiations as they directly bear the cost, rather than having *de facto* cost pass through and a guaranteed market position. This amplifies the effect of different risk averseness. The factors influencing bargaining positions are described in Table 16.1.

Table 16.1. Factors affecting negotiating strength of types of bargainer

Bargainer	Factors leading to strong negotiating power		Factors leading to weak negotiating power	
	Factors favouring risk neutrality	**Factors favouring high bargaining strength**	**Factors favouring risk aversion**	**Factors favouring low bargaining strength**
Producers	• Rents go to government (owner) for general use	• Few producers, each with large volume	• None	• Hard currency exports key to economic welfare
Transmission costs	• None	• Large buyers	• Large rents risk attracting regulatory attention • Low rents sufficient to ensure organizational 'comfort'	• Legally required only to cover costs (cost plus prices) in some countries
Power plants	• Need to remain competitive if power market competitive	• Large buyers (especially if several plants) • Attractive load pattern if baseload	• Gas plant economic at wide range of prices if competitive with coal	• Smaller demand than transmission companies
Distribution companies	• None	• Public attention to residential prices	• Public supply obligation	• Unattractive load pattern • Smaller than transmission company
Large consumers	• Need to remain competitive in world markets	• Can be large buyers, or part of group of large buyers	• None	• Small relative to transmission company
Small consumers	• None	• None	• Energy costs small proportion of budget	• Small

Source: modelling assumptions

16.2.2. Possibility of a more competitive outcome

The possibility remains that implicit collusion may not be maintained under TPA, or that it will be incomplete. We have therefore addressed the possibility that collusion will be only partial with some competition between producers. For simplicity this is addressed within the same modelling framework, but assuming that customers have greater bargaining power, and are thus able to secure a greater proportion of the rents. In a fully competitive market the marginal producer would secure no rents, with other producers gaining only the difference between their costs and those of the marginal supplier.

The main factors which would tend to favour a more competitive outcome are as follows:

(a) *A sustained increase in the availability of UKCS gas.* If significantly larger volumes were to become available through the interconnector with continental Europe on a sustained basis, this would encourage competition. We have not adopted this assumption because the existing reserve position in the UK and the very strong demand growth from the power sector suggest that this is unlikely. However, major new discoveries could change this position somewhat. In the absence of major UK discoveries, a UK market 'reference price' may figure in negotiations, but the ability of buyers to obtain such a price from other producers seems limited if the buyers do not have the alternative of UK gas available to them in practice.

(b) *A sustqined major increase in Dutch exports.* This is considered unlikely for the reasons noted above. However, a major policy change from the Dutch government could stimulate competition, although at the expense of increasing import dependency in the long term.

(c) *Revenue requirements of the major exporters leading to pressure to cut prices and gain market share.* Russia and Algeria both require hard currency from energy exports. This may increase the pressure to offer price cuts to increase market share. However, they would be expected to recognize the dangers to revenues of a price war, and the limitations on their ability to grow market share imposed by diversity of supply requirements. For this reason, we have adopted the view that such behaviour will be marginal. However, if it were to become a significant feature of the market, this could significantly reduce prices.
The main incentive to increase volumes may come if large amounts of very low cost Russian gas become available. However, their share of new supply will, in any case, be large and it remains unclear that gaining market share will be preferred to maintaining high prices as a means of maximizing revenue. The possibility of major new Russian sales to the power sector is acknowledged and the desirability of ensuring the right to build independent pipelines (such as the Wintershall line) in order to allow for this possibility is among our main conclusions.

(d) *A reduction of state control.* If each of the major exporters were to be represented by several producers freely competing to sell gas (as in the UKCS), the prospects for competition would be greatly enhanced. For example, if numerous independent producers were to emerge in Russia with open access to the Gazprom system, this would tend to lead to the emergence of true gas-to-gas competition. However, it is not in the interests of the countries concerned to allow this as it would entail losing control of natural resource rents. Consequently, although we expect foreign investment in Russia and Algeria (such as the BP venture referred to in the section on supply), this seems unlikely to lead to a loss of state control. A reduction in state control among existing exporters would represent the most powerful route to increasing competition in the gas sector.

(e) *Other significant exporters to Europe emerging.* If Iran or Turkmenistan were able to secure independent exports of gas, or very large quantities of LNG were to be sold into the European market, this would make the market much more competitive.

(f) *Differences in objectives between main producers.* The main exporters may have different objectives: for example, Russia may, as noted, wish to increase export volumes, and Norway may attach priority to maintaining cordial relations with the EU. However, it appears unlikely that this will override the desire to maintain high prices. In particular, Gazprom's various marketing ventures, such as Wintershall, appear to be more an indication of a desire to circumvent the existing transmission companies than a sign of increased competition.

16.3. Modelling assumptions

We have summarized these in two cases of bargaining effectiveness, each of which may apply separately to various sectors (e.g. distribution companies may be risk averse, large industrial customers may not):

(a) transmission companies are less effective negotiators than customers (more risk averse and/or lower bargaining power);

(b) transmission companies are more effective negotiators than customers (less risk averse/higher bargaining power).

These scenarios are quantified using the assumptions in Table 16.3. The quantification of parameters for bargaining strength and risk aversion is inevitably rather arbitrary when comparing the outcome of the present situation with that of TPA, because:

(a) the bargaining strength of players not presently participants in the bargaining process (namely customers) must be estimated for a TPA environment. This is inevitably speculative;

(b) the parameters cannot be measured directly, but must be inferred from the outcome of previous negotiations, and other data. Existing rent allocations are difficult to measure with any confidence.

For these reasons we have relied on consideration of fundamental drivers to quantify parameters, rather than attempting to use an explicit methodology. The key aspect of the modelling is the ranking of the various parties under each parameter, rather than the absolute values of each parameter.

The producer's bargaining effectiveness is taken as 1 to provide a reference point. Transmission companies are assumed to be less effective negotiators than producers, capturing only a small proportion of the rent at present. Customers are shown to be less effective negotiators than transmission companies are at present in Case 1 (see Table 16.3), and more effective negotiators than transmission companies in Case 2.

The transmission company is shown as excluded from the negotiations under TPA. This appears realistic under full TPA, where an access price is externally determined. Under nTPA, the transmission company will clearly retain a place in negotiations. However, for modelling purposes we have (as described in the previous section) treated this by assuming they retain implicit rents, but are not able to gain access to other rents so:

(a) under nTPA, implicit rents are assumed to stay with the transmission company, other rents to be split between producers and customers;
(b) under TPA, implicit rents are also allocated between producers and customers.

The results of these assumptions are described in the next chapter.

Table 16.2 summarizes the numerical assumptions on market value and production costs drawn from previous sections, which defines the amount of rent to be bargained for. New Russian gas is chosen to illustrate marginal supply options. Transmission costs from the European border to the customer are assumed to be US$ 0.2/MMBtu, with implicit rents of US$ 0.1/MMBtu due to additional costs. The assumption on the magnitude of implicit rents due to additional costs is inevitably judgemental, as there is no reliable way of measuring additional costs from data in the public domain. The rent assumed presently to accrue to transmission companies is very large relative to their costs, but small as a proportion of the overall price, because transmission within the borders of the EU is a small proportion of total costs. It appears unlikely that rents could be much larger as a proportion of costs without attracting evident attention (although additional rents may well be present in the distribution companies). Assumptions are also shown for price elasticities and volumes affected by TPA. The results are not sensitive to assumptions about price elasticities provided that they remain low. The volumes affected are based on the likely sizes of the markets. This will clearly change through time.

Costs are assumed not to vary between the scenarios, as they reflect the resources necessary to deliver the gas. It may be argued that the cost of capital would increase under a TPA regime because of the increased market risk. Under the present regime, long-term contracts reduce financing risk and so may reduce the cost of capital for a pipeline project. However, to the extent that they were economic risk reduction measures, they would occur in a liberalized market through contracts, including forward contracts etc. In other cases, existing structures may include a hidden appropriation of value by existing market participants. For example, the existing merchant may restrict demand growth rather than contract for extra supplies, reducing market risk by depriving customers of value, or may effectively cross subsidize from the transport business by providing contracts with recourse to physical transmission and distribution assets. It is, therefore, unclear that there is any true increase in risk or cost of capital. In any case, the presumption in introducing competition, supported by experience elsewhere, is that the benefits from competition outweigh any costs. The key issue in this report is whether the potential for significant competition exists.

16.4. Sensitivity of results to assumptions

The general magnitude and direction of results is not sensitive to the parameters specified (although clearly quantifications change somewhat). The results depend on the relative magnitude of the variables, rather than their numerical values. Specifically the direction and broad magnitude of the changes remain valid provided the following remain:

(a) pricing of gas at close to market value,
(b) relative bargaining strengths of participants,
(c) relative magnitudes of costs.

Base case results are shown in the next section, and sensitivities described. Numerical sensitivities are shown in the Appendices to illustrate the variation in outcomes.

Table 16.2. Summary of value chain and other assumptions (US$/MMBtu)

	PG	Industry	Notes
Value of gas	4.20	3.50	See Chapter 5
Cost of production and delivery to border	2.73	2.73	Both baseload, see Chapter 4
Cost of transmission	0.20	0.20	Assumption
Implicit rent in transmission (inflated costs)	0.10	0.10	Assumption
Other rents	1.17	0.47	Value-costs

Other assumptions:

	PG	Industry	
Elasticities of demand	0.5	0.6	Assumption
Volume affected (bcm p.a.)	50[1]	25[2]	Assumption

Source: modelling assumptions

[1] The majority of incremental gas in the power sector outside the UK, post 2000.

[2] Equivalent to approximately 30% of industrial gas demand.

Table 16.3. Rent allocation from bargaining effectiveness

Scenario		Case 1: weak customer bargaining		Case 2: strong customer bargaining	
		Bargaining effectiveness	Share of rent (%)	Bargaining effectiveness	Share of rent (%)
Present situation	Producer	1	83	1	83
	Transmission company	0.2	17	0.2	17
	Customer	n/a	0	n/a	0
nTPA or TPA	Producer	1	91	1	71
	Transmission company	0	0	0	0
	Customer	0.1	9	0.4	29

Source: LE estimates.

16.5. Modelling of different consumer classes

Consideration of the factors shown in Table 16.1 suggest that:

(a) power plants and large industrial customers are likely to be more effective negotiators than transmission companies;
(b) small consumers and distribution companies may be less effective negotiators than transmission companies.

For the scenarios including implicit collusion (see next chapter) the results of the modelling work for effective negotiators are taken to apply to power plants and large industry, the results for less effective negotiators are taken to apply to small consumer and distribution companies. It is possible that small consumers could form consortia to increase their negotiating strength. However, although this may mitigate some of the factors leading to weak negotiating power, others will remain unaffected and so it seems likely to reduce the magnitude of their disadvantage but not to eliminate it. In the scenario showing gas-to-gas competition, all consumers are assumed to be effective negotiators.

17. Results of the modelling work

This chapter describes the results of the modelling work. Scenarios are described that include implicit collusion on price among producers, and gas-to-gas competition. The base case, with implicit price collusion among producers, is first described (Section 17.1). Sensitivities to this are then examined (Section 17.2 and Section 17.3). Finally, an alternative scenario showing the consequences of greater gas-to-gas competition is examined (Section 17.4). The numerical results are taken as from the bargaining model. Qualitative support for the results comes from the oligopoly models which are described in the Appendices. All quantitative results must be regarded as indicative in view of the uncertainties attached to parameters.

17.1. General outcomes

The models show that prices to customers are fixed just below the level at which it would be more economic to use another fuel. This is consistent with observed behaviour in the market. The model shows modest rents flowing to transmission companies, which is consistent with the observed rates of return and lack of marked cost pressure. Rents consist of explicit rents and disguised rents (higher than necessary costs). Rents to producers are large, consistent with a comparison of production costs and present border prices. Indexation of long-term gas imports to oil is designed to ensure that producers get a substantial share of any rent due to oil price rises, while transmission companies are able to keep prices competitive if the oil prices fall. Such a model is also likely be valid in the power sector based on consideration of fundamental drivers and limited evidence from the few contracts agreed to date. This is in marked contrast to the more competitive UK gas and power market which shows true gas-to-gas competition and cost based prices.

The results of the scenarios for the central case data assumptions are now summarized. Sensitivities and the alternative gas-to-gas competition scenarios are described below. As noted in Section 16.2, the possibility of implicit collusion between producers exists in any case. The difference between scenarios is the effect of downstream industry structure on the revenues they are able to obtain.

17.1.1. Scenario 1: The present situation

Under this scenario the price is fixed at the revenue maximizing level. Rent accrues to the transmission companies and the producers. The major part of the rent accrues to the producers, because they have greater bargaining power. However, the transmission companies gain some rent, which is increased by uncertainty about their true costs.

17.1.2. Scenario 2: Negotiated TPA

This is intermediate between the full TPA scenario and the present situation. The removal of exclusivity rights may also limit the amount of rent transmission companies are able to extract, especially in the case of the power sector. Results are shown in Tables 17.1 and 17.2.

Prices for access lack transparency, allowing transmission companies to keep implicit rents. Other rents are divided between producers and customers. The extent of the benefit to customers varies from some ECU 250 million to ECU 800 million, depending on their bargaining power, due to price reductions in industry and in the power sector. However, the net benefit to the EU as a whole is markedly different depending on whether the customers have greater or lesser negotiating power than the transmission companies. In the latter case, some ECU 400 million of rent flows out of the Community to the producers. In the former case, producers also gain rent, due to a slightly expanded market, but not at the expense of parties within the EU.

Increases in volumes are modest (1 to 3 bcm, less than 1% of the market in 2005), reflecting inelastic demand modest price charges and the opening of only a small proportion of the market to TPA. These volumes are less than a single year's market growth. Trade increases by a similar amount as indigenous production is little affected (a small increase in indigenous production to meet local demand in the Netherlands being a minor potential exception). Volume growth would be greater in circumstances where transmissions companies were presently restricting volumes because of low present profits, accompanied by inability to capture full value by price discrimination.

17.1.3. Scenario 3: TPA

The rent presently earned by transmission companies (both implicit and explicit) is lost provided the price of access is set at true cost. The rent will be divided between producers and customers. It is expected that consumers will be unable to secure all of this. In particular, consumers' bargaining power will be weakened by producers' improved ability to price discriminate, by the transparency of access prices and, to a large extent, by increased transparency of transmission company costs. Some buyers will also be more risk averse than the transmission companies. However, some customers, mainly in energy intensive industries, will be more risk tolerant and may seek to negotiate more aggressively. This should allow them to gain a larger proportion of the rents. A caveat to this is that the producers may expect to gain something from the deal, and they will still have the option of selling to the transmission company.

The financial consequences of TPA are broadly similar to those of negotiated TPA. The main difference is that implicit rents due to inflated transmission company costs are removed. These are allocated among customers and producers according to their degree of bargaining power. We have assumed that such disguised rents are not large in absolute terms, as transmission costs within a country are not a large proportion of total costs. More rents may exist in the distribution parts of the business, but this is to remain a monopoly and so these are expected to be retained by the present distribution companies.

Consumption will increase only slightly as the elasticity of demand is low. Cross-border trade will increase by an amount similar to the rise in demand as under TPA. If rents are not present in the industrial sector, market volumes may be further increased by price reduction due to loss of implicit rents.

17.2. Sensitivities

We have modelled the following sensitivities, which are shown in Tables 17.1 and 17.2.

(a) *Lower gas value*: a reduction in the value of gas reduces the amount of rent to be bargained for. The effect is similar to that of an increase in costs. Gas values are assumed to be reduced to US$ 3.50/MMBtu in the power sector (perhaps because of the threat of competition from long-distance LNG), and to US$ 3.10/MMBtu in industry (reflecting lower oil prices).

(b) *Higher transmission company rents*: this assumes that a larger proportion of rents are currently being gained by the transmission company. US$ 0.30/MMBtu of rent (including inflated costs) are included in this case. This is a very large sum in proportion to costs, and may be considered an upper bound figure.

The results of these sensitivities are shown in the tables below. The following results are common to all scenarios:

(a) Prices to consumers fall in all scenarios as they accrue rents presently accruing to the transmission company. The fall is greater in a TPA environment than in an nTPA environment. There is consequently a net gain to consumers which, in the case of 'Scenario 2, strong negotiating power' (considered more realistic for large consumers), varies between some ECU 300 and 1,400 million p.a.

(b) The border price rises if consumer negotiating power is weak, but tends to fall if it is strong. However, the effect of consumer negotiating power in reducing border price is offset to a greater extent in the TPA case as the producer is able to gain implicit rents previously retained by the transmission company. The border price therefore rises slightly in some cases under a TPA environment, even if consumers are stronger negotiators than the transmission company (because costs are now more transparent). In all cases except that of strong consumer negotiating power, producers experience a modest net revenue gain as any small price falls are offset by an increase in the volume of sales.

The results for individual cases are:

(a) *Lower gas value:* price falls are reduced as there is less rent to bargain for. The border price is somewhat higher in scenario 2 as there is less opportunity to offset the effect of the producer gaining transmission company rents. Gains to both producers and consumers are smaller as there is less rent, and volume increases are consequently smaller.

(b) *Higher transmission company rents:* here the main effect is to increase the difference between the nTPA and the TPA scenarios. The greater amount of transmission company implicit rent (inflated costs) that the producers have access to in the TPA case causes border prices to be higher than in the nTPA case, where the transmission company retains these.

17.3. Effect of other changes

17.3.1. Carbon tax

A carbon tax would raise the value of gas against other fuels. For example, a tax levied entirely on CO_2 content at the level of US$ 10/bbl of oil would raise the value of gas in industry by US$ 0.65/MMBtu and in power generation by US$ 2.25/MMBtu. This would directly increase the amount of rent in the chain by an equivalent amount, unless other measures were also taken which had a counterbalancing effect. In practice, rents in the power sector would be so large that some other factor, such as the cost of alternative supply, would limit them.

Table 17.1. Comparison of sensitivities (scenario 1 – weak customer negotiation)

Scenario	Change in price to industry (US$/MMBtu)		Change in price to power generators (US$/MMBtu)		Change in border price[1] (US$/MMBtu)		Total gain for consumers (million ECU)		Net change in producer revenue (million ECU)	
	nTPA	TPA	nTPA	TPA	nTPA	TPA	nTPA	TPA	nTPA	TPA
Base case	-0.04	-0.05	-0.11	-0.12	0.07	0.15	256	283	332	621
Lower gas value	-0.01	-0.02	-0.04	-0.05	0.3	0.12	91	119	118	406
Higher transmission company rents	-0.02	-0.05	-0.09	-0.12	0.05	0.32	201	283	256	1,121

Source: model results
[1] Average of industry and power generation.

Table 17.2. Comparison of sensitivities (scenario 2 – strong customer negotiation)

Scenario	Change in price to industry (US$/MMBtu)		Change in price to power generators (US$/MMBtu)		Change in border price[1] (US$/MMBtu)		Total gain for consumers (million ECU)		Net change in producer revenue (million ECU)	
	nTPA	TPA	nTPA	TPA	nTPA	TPA	nTPA	TPA	nTPA	TPA
Base case	-0.13	-0.16	-0.33	-0.36	-0.10	-0.04	803	889	20	282
Lower gas value	-0.02	-0.05	-0.13	-0.16	-0.04	0.04	289	375	8	267
Higher transmission company rents	-0.08	-0.16	-0.28	-0.36	-0.08	0.16	631	889	1	782

Source: model results
[1] Average of industry and power generation.

17.3.2. Other cost and price changes

If production costs are higher or lower than shown then the amount of rent will be correspondingly changed. For example, new Algerian supplies may have an additional US$ 0.75/MMBtu of available rent. Norwegian producers may have US$ 0.5/MMBtu less rent available.

A rise in oil prices would increase rents in the industrial sector. Continuing improvements in thermal efficiencies of CCGT plant will also tend to raise rents in the power sector, subject to the cap imposed by the costs of LNG imports. Changes in the amount of rent will not change the conclusions reached here, but will change the size of the costs and benefits of reform.

17.3.3. Bargaining strengths

As noted, the assignment of bargaining strengths has an inevitable degree of arbitrariness. However, the ordering of these (i.e. which is greater than another) is the key to determining the outcome. The higher the present bargaining strength of the transmission company, the less plausible is the hypothesis that some customers would have greater bargaining power than the transmission companies. However, as noted, the border price of gas and the comfortable but not spectacular profitability of the existing transmission companies make it seem unlikely that they are at present gaining the majority of the rents.

17.3.4. Cost of alternative pipelines

If TPA is not introduced, the amount of rent that transmission companies may extract is, in principle, limited by the possibility of building independent pipelines. For small volumes this will be prohibitively expensive, because the necessary economies of scale will not be achievable. However, in the power sector volumes consumed are large. 1 GW of CCGT consumes some 1.3 bcm p.a. of gas in baseload. A small group of power stations could therefore support a pipeline of moderate size. For example, a 5 bcm pipeline running 200 km from a border need only incur costs of US$ 0.14/MMBtu.

If exclusivity rights for pipelines are removed, this should allow groups of power plants to negotiate their own deals using relatively short pipelines from the border to the plants, and incur only modest cost in doing so. This will allow many of the gains from increased bargaining power from TPA to be realized even in the absence of TPA to existing networks. As such it constitutes an important limitation on the oligopoly power of transmission companies, but emphasizes the importance of bargaining between customers and producers.

17.4. Alternative scenario with greater price competition between producers

We have examined an alternative scenario which assumes increased competition among producers. In this scenario producers do not collude, but compete actively to win customers by offering price reductions. This is one of the classic 'textbook' forms of behaviour postulated for oligopolists competing in a market on price.[36] The presumed consequence is that each producer reduces his prices in the hope of gaining market share. This is followed by a price response from other producers, and so on until prices reach the floor imposed by the costs of production. As in any competitive market, consumers appropriate much of the rent, with prices potentially being driven down to marginal cost.

In terms of the framework used in this work, this implies that producers' ability to bargain for rents by raising prices will be reduced by pressures to gain market share. This increases the power of consumers who are able to secure a better deal. TPA may facilitate this by providing easier access by consumers to producers, encouraging producers to compete for market share by pricing keenly. The ability of producers to maintain prices that exists under the present industry structure (foregoing only a limited amount to the transmission companies) is assumed to be greatly reduced under TPA by granting consumers direct access to producers, stimulating true competition.

We have modelled the effect of such gas-to-gas competition within the same framework used for the base scenario for ease of comparison, expressing the effects of competition in terms of increased negotiating power for consumers. This is shown in Table 17.4. The negotiating power of consumers is assumed to increase to 40% of that of the producer in scenario 1, and 80% of that of the producer in scenario 2 (totalling over ECU 1 billion p.a.). This creates large gains for consumers at the expense of producers. These are larger in the TPA case than in the nTPA case. In practice the gains may be even greater than shown, as they may apply to a larger

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36 It is referred to as Bertrand competition.

segment of the market; and because the effective negotiating power of consumers may increase beyond that shown.

This scenario clearly suggests that liberalization would produce major benefits if there were a large degree of price competition among producers.

Table 17.3. Results of increased competition scenario

Scenario	Change in price to industry (US$/MMBtu)		Change in price to power generators (US$/MMBtu)		Change in border price[1] (US$/MMBtu)		Total gain for consumers (million ECU)		Net change in producer revenue (million ECU)	
	nTPA	TPA	nTPA	TPA	nTPA	TPA	nTPA	TPA	nTPA	TPA
Weak consumer negotiation	-0.13	-0.16	-0.33	-0.36	-0.10	-0.04	803	889	20	282
Strong consumer negotiation	-0.21	-0.25	-0.52	-0.56	-0.23	-0.18	1,249	1,382	-255	-20

Source: model results

[1] Average of industry and power generation.

18. Conclusions and policy implications

18.1. Conclusions

This chapter summarizes the conclusions of the analysis presented here, then assesses the implications of these for policy.

Given the structure of the industry that we have described, we conclude from our analysis that:

(a) There are likely to be advantages for TPA to gas transmission networks for large industrial consumers and power generators, because they will have the incentive and ability to negotiate more effectively than the present transmission companies.

(b) This should increase the competitiveness of energy intensive industry in the EU by securing lower energy prices. The total saving to consumers could be some hundreds of millions of ECU. TPA will also give greater commercial freedom for IPPs to buy gas even when it does not significantly further the interests of the transmission company, and is also likely to be a necessary condition for increasing integration of gas and electricity markets. This should aid economic efficiency by allowing resources to be properly allocated across the two sectors.

(c) The advantages of TPA for distribution companies are less clear, because distribution companies may be less effective negotiators than transmission companies, and so one effect may be a transfer of additional economic rent outside the EU. There may be some reductions in city gate prices, but it is unclear whether these will be transferred to the consumer rather than appropriated by the distribution company unless there is TPA to all consumers, which seems a distant prospect. If distribution companies cannot obtain reduced prices under TPA, they may seek to continue obtaining gas as at present. There may also be increased direct marketing by producers.

(d) If TPA were to lead to vigorous price competition among producers (full gas-to-gas competition), there would be likely to be much greater benefits to consumers, although in the absence of full competition in supply to individual consumers, the risk of distribution companies appropriating many of the benefits would remain.

(e) There are no compelling reasons for exclusive rights to build pipelines. It should be possible to assure adequate standards of health and safety during construction and operation by means of legislation on these matters.

(f) Ensuring the right of independent parties to build pipelines may be a key element in allowing the gains from the increased use of gas in the power sector to be realized. Many of the savings for consumers from TPA in the power sector could be achieved by allowing independent pipelines (even without TPA), provided that the ability of independent generators to build and operate power plants exists. If there is no right to build independent pipelines, independent power producers may not be able to contract for gas successfully, and this would significantly impair the growth of competition in electricity generation.

(g) TPA seems unlikely to lead to major additional costs. Any increase in risk is mainly a transfer of risk from the consumer to the industry. If long-term contracts for supply are required, for example because assets are locked in, then these will follow from the market in any case.

(h) Liberalization of the electricity sector is likely to have a major effect on the gas industry. This is because liberalization of electricity will assist in realizing the huge potential market for gas in the power sector. Similarly, liberalization in the gas market is likely to be beneficial to the liberalization of the electricity sector and may in some respects (such as allowing the construction of independent pipelines) be a condition for realizing the full potential of liberalization in the power sector.

(i) As with electricity, the natural monopoly characteristics of the network will lead to the continuing need for regulatory oversight.

18.2. Policy issues for gas

This section of the report summarizes our conclusions on the main points of interest highlighted in the terms of reference. The structure of this section is the same as the corresponding section for electricity, for ease of comparison.

In many cases, the effects of completing the single market for gas are smaller than those for electricity, because of the problems with introducing competition described in this report. The main effect of introducing TPA is likely to be to redistribute economic rent between the parties in the value chain. Without more extensive liberalization, including the upstream, there is little true increase in competition in production or network construction and operation, the major sources of costs, so there is only a limited effect on productive and dynamic efficiency. Prices and availability of supply also change little, so there is also likely to be little effect on allocative efficiency. The main caveat to this is that there may be some increase in productive efficiency in transmission as the construction of independent pipelines and storage and greater cost transparency increase pressure on the transmission companies to bring their costs down and result in a more efficient and integrated grid. The effects of increased efficiency have been treated in the modelling as a loss of rents presently disguised as inflated costs ('implicit rents').

The effect of completing the single market is considered under the following headings.

18.2.1. Energy consumption patterns

There is expected to be an increase of gas consumption of 2 bcm p.a. as a result of nTPA and 3 bcm p.a. as a result of full TPA. The rise is small because the demand for gas is inelastic, price falls that result from TPA are small, and only part of the market (large industrial consumers and power generators) is assumed to be affected. This increase excludes the potential additional volumes from increased use of gas in power generation which may follow from the liberalization of electricity markets and the construction of independent pipelines.

18.2.2. Energy production patterns

Production within the EU tends to be driven by availability of reserves, security of supply and load balancing requirements, and national policy on extraction of natural resources. There is little potential for increased production outside the Netherlands and the UK. Policy in the Netherlands seems unlikely to change, so the effect of TPA will be small. There may be some increase in UK exports down the interconnector in the short term, with a correspondingly earlier reversal of flow to import gas. The capacity of the interconnector is 15 to 20 bcm p.a., and significant quantities are expected to flow in all scenarios. The maximum change in annual production therefore seems likely to be 5–10 bcm. With negligible changes in production elsewhere, production changes seem likely to amount to only 2–4% of total EU gas consumption.

18.2.3. Price and cost effects for certain categories of consumer

As noted, prices to large industrial consumers and power plants are likely to fall slightly, perhaps by some US$ 0.1/MMBtu to industry (approximately 3%) and US$ 0.2–0.3/MMBtu to the power sector (5–8%). Prices to residential consumers are unlikely to fall. There is a theoretical possibility that they might rise due to weakening of the bargaining power of distribution companies, but this seems unlikely to occur in practice as they will have the option of continuing to buy from the transmission companies.

It should be noted that there is no double counting of gains in the power sector if these are added to the benefits shown in the electricity section. The base case analysis for electricity assumes a high gas price, comparable with that shown here. The 'high gas' case for electricity does assume a lower gas price (US$ 3.50/MMBtu), and in this case gains may be as shown in the 'reduced rent' sensitivity for gas.

Greater gas-to-gas competition is shown to lead to savings of ECU 0.9–1.4 billion p.a. These savings would be much greater if TPA were extended more widely, as would be appropriate in such a case.

TPA may reduce the potential for price discrimination by permitting ready on-selling of gas. It is assumed by some that price differences are removed by consumers or traders with access to lower priced gas buying additional volumes at the low price, and selling them for a very small margin. However, in practice this may be limited by the power of the producers who may seek to price discriminate to extract maximum value from the market.

18.2.4. Levels of investment in capacity and network links

As consumption is unchanged, investment levels are also likely to be little changed. Increased demand of 3 bcm p.a. would require increased investment of ECU 190 million,[37] but in practice this may be met from existing capacity and more efficient use of the network.

There may be some efficiency gains in transmission capacity construction due to the removal of exclusivity rights and increased transparency of transmission costs. Savings would be expected to come from two main sources. The first would be competition leading to more efficient construction of new capacity. The second would be the construction of additional links and new storage facilities that would remove inefficiencies and bottlenecks in the system. It is also possible that a TPA regime would reduce inefficiencies by increasing transparency of costs for existing networks. This is modelled in the present study as the loss of transmission company implicit rents but is difficult to quantify without detailed technical modelling of the network, which is outside the scope of this study.

If costs for new transmission capacity were reduced by 10%, as is assumed for electricity, this would lead to a reduction of some 1% or less on total gas costs, as transmission remains a

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[37] Based on the assumption that the gas would flow on average 500 km through a line with capacity of 10 bcm p.a., the remaining capacity in the line being occupied by other gas.

small proportion of the overall cost of providing bulk gas, and the savings would only apply to new capacity. This is equivalent to approximately ECU 220 million p.a. However, it is unlikely that all of this would be realized as competition would probably be less fierce than in electricity generation. A figure below this therefore seems more realistic.

There is the possibility of significant additional investment if independent pipelines are built to serve power sector demand that would not otherwise be served, due to the existing transmission companies restricting the market. The potential additional investment in this case would be large. For example, if there were an extra 20 GW of plant, consuming 26 bcm p.a. of gas transported an average distance of 400 km, this would require an additional ECU 1.3 billion of investment.[38]

18.2.5. Capacity utilization

Again this would be expected to be largely unchanged. It could be that some part of the additional volume consumed would increase utilization, especially off peak. There is also the possibility that further competing capacity would be built following the removal of exclusivity rights leading to a fall in capacity utilization. However, detailed modelling of the network is outside the scope of this project.

18.2.6. Level and pattern of cross-border trade and sourcing by independent parties

Again, as consumption is likely to increase little, and most gas must come from sources outside the EU, there would be little change in cross-border trade within the EU. The main potential changes are the increase in the flows from the UK referred to above, and the possibility of gas moving to power plants via independent pipelines.

18.2.7. Level of import dependency and sources of imports

The level of import dependency will increase under all scenarios. It is not likely to be very different under the TPA scenarios, as there will be a continued requirement to source from each of the major suppliers. The small increase in total volumes will lead to a corresponding small increase in overall import dependency for the Community. The issue of import dependency is discussed further below.

If the ability to build independent pipelines leads to additional demand, then this will correspondingly increase import dependency.

18.2.8. Requirements for investment in interconnection

The Commission identifies several projects that are required to complete the single market (see Chapter 12). They are all likely to proceed under each of the three scenarios, and so will be little affected by the introduction of liberalization. However, each is a valuable step towards increasing coherence of the Community's energy systems. The UK interconnector is especially valuable in this respect. The total investment is likely to be of the order of ECU 2.2 billion.

38 Gas is assumed to move via a 10 bcm p.a. capacity line.

18.2.9. Security of supply and balance of energy sources

Security of supply will reflect import dependency, as described above. Measures to improve security of supply are described below.

18.2.10. Contribution to the competitiveness of Community industry

There is likely to be a modest contribution to the competitiveness of Community industry, from the reduction in price to large industrial consumers.

18.2.11. Impact of difference in indirect taxation or subsidization of energy consumption

Taxation of oil products will continue to have an effect on the price of gas. To the extent that this is harmonized, there would be expected to be some convergence of gas prices in the EU. The extent of present differences in taxation are shown in Appendix B.5.

18.2.12. Environmental consequences

The modest increase in gas consumption will produce some environmental benefits by reducing CO_2 emissions, presuming gas displaces other fuels. However, there is a danger of an increase in methane emissions if imports from Russia increase. This is discussed further below. Our base case results show an additional 0.7 bcm p.a. of consumption in industry, and an extra 2.2 bcm p.a. of consumption in the power sector. This would result in emissions reduction of some 8 million tonnes of CO_2 p.a.[39] assuming gas displaced fuel oil in industry and coal in power generation. In practice, some of these savings may not occur as some consumption growth will be from a general increase in energy use, rather than the substitution of one fuel for another.

18.2.13. Possibility of increased rivalry between producers

The above conclusions correspond to the limited competition scenario. The scenario showing greater price competition between producers would result in the following principal differences:

(a) Price falls to consumers would be greater, especially for power plants, where rents are presently greatest. Industrial consumers may also experience price falls. Residential consumers may also experience some reduction in prices, but some may be appropriated by the distribution companies.
(b) Sales volumes would increase somewhat.
(c) There may be some pipeline over-capacity as competing pipelines are built.
(d) Import dependency would rise as volumes increased.
(e) The contribution to the competitiveness of Community industry would be greater, corresponding to the increased price falls.
(f) Patterns of production would not be significantly affected, although some of the increase in UK volumes may be displaced by other sources, most likely Russia.
(g) Increased consumption would also lead to greater environmental benefits.

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39 See Appendices for details of CO_2 emissions by fuel type.

18.3. Policy issues for gas

Policy measures need to seek to address the key drivers of the outcomes identified in this report. These are:

(a) The form of demand. This is set by fundamental economic considerations, and is likely to be difficult to influence by policy.
(b) The price of competing fuels. These are set by world markets. However, EU tax rates have an influence on consumer prices.
(c) Concern on security of supply. The EU may be able to take measures, such as assisting strategic storage, which ease concerns in this area.
(d) The number of producers. Increasing the number of producers able to supply the market is likely to be a key policy objective.
(e) The bargaining power of customers. This may be affected, e.g. by permitting TPA only for certain classes of customers.
(f) The bargainers for rents in the chain. By becoming a *de facto* participant in bargaining (e.g. by imposing taxes), the EU may change rent allocations.

The last four of these issues, and other policy matters, are now discussed.

18.3.1. Security of supply

The potential growth of demand in the power sector poses clear challenges for policy. A *laissez faire* approach would lead to very great reliance on imports, especially from Russia, which would expose the European Union to the possibility of supply interruptions disrupting the gas and electricity industries simultaneously. The policy implications of this mainly relate to security of supply in electricity, and are discussed in the corresponding chapter on electricity. It is possible that the greater reliance on Russian gas due to demand growth in the power sector could have a deleterious effect on the security of gas supply in other sectors. However, if there is a major supply interruption from Russia, and there are adequate arrangements, such as dual firing of power plants, this need not be so. Indeed, if there is a large proportion of interruptible contracts for power plants, demand growth from the power sector may serve to enhance security of gas supply for other sectors.

Security of supply may be further enhanced by conservation of energy. These benefits should form part of the equation when considering the desirability of such measures, along with the well recognized environmental and other benefits.

Extra strategic storage may be required as import dependency increases. This may best be realized by the gas companies engaging in competitive tender.

The completion of trans-European gas networks will also have an important role to play here. The projects identified in the Commission's recent document on trans-European energy networks (*Trans-European Energy Networks, Community Guidelines for Projects of Common Interest* [1995], European Commission DG XVII) will all assist in this respect, particularly in reducing the vulnerability of individual Member States to interruptions from a supplier on which they are especially dependent. However, the main contribution to increased security of supply would come from increasing the diversity of import sources, and this is discussed further below.

18.3.2. Environmental policy implications

TPA would have few direct effects on consumption, and so few environmental effects. However, the effects of increased gas consumption in the power sector must be considered. In many ways, increased gas consumption will provide benefits, with negligible emissions of sulphur and reduced emissions of CO_2. However, the issue of methane emission from the gas system, especially outside the EU will need to be addressed, because methane is such a powerful greenhouse gas. The Russian system is likely to be especially problematic in this respect, because of the high level of losses from the system.

18.3.3. Addressing the problem of the upstream oligopoly

The most significant contribution to addressing the problem of diversity of supply would be to increase the number of gas importers. The best prospects for increased large-scale imports by the EU are from the republics of the former Soviet Union, especially Turkmenistan, exporting via routes other than through Russia. Supplies from the Middle East could also make a significant contribution. The main problems with securing these supplies are the political difficulties along the route which they must traverse, and the corresponding difficulty in financing projects. Assistance from the EU to alleviate these difficulties may have substantial benefits.

LNG imports will also have a contribution to make. Facilitating planning permission etc. for LNG terminals may be helpful in increasing the diversity of suppliers, but direct subsidies may be ineffective as they may simply weaken the incentive on LNG providers to keep reducing their costs, on which good progress is being made. Instead, assuring readier access to markets by removing barriers may stimulate efforts by producers to reduce the costs of long-distance deliveries, especially of LNG, and so increase diversity of supply.

18.3.4. Rent flows

The potential for rents in the value chain to be appropriated by producers could be addressed directly by fiscal measures, perhaps, for example, a licence fee for transmission pipelines calculated at the point of entry. This would be equivalent to transit tariffs common among the countries through which major gas lines pass. Licence fees would in effect raise transmission costs and so reduce the amount of rent in the chain for which the industry could bargain.

A final possibility would be to tax gas as it is consumed. There is now a tax in Germany, but in most countries there is no equivalent for gas of the excise tax on oil products. However, such a tax would risk restricting demand growth among marginal consumers. The most effective measure might be to place a tax on the use of gas in the power sector, where rents are very large; and there may be a desire that potential demand, which is enormous, be constrained.

18.3.5. Maintenance of buyer concentration as a policy mechanism

The problem of upstream oligopoly does not imply that it is desirable to balance this with an oligopoly of buyers (the transmission companies), as happens at present. This produces no benefits for the consumer, as it simply leads to rent capture by the transmission companies. Rather, the preferred solution is to implement policies that increase competition in production, and to seek to appropriate rent for consumers, whether directly or via official institutions, in the form of licence fees or taxes. Maintenance of the existing structure simply compounds one problem (upstream oligopoly) with another (downstream oligopoly), whereas an appropriate policy solution is likely to involve addressing directly the problems caused to consumers by the presence of an upstream oligopoly.

18.4. Summary of main policy conclusions

The main conclusions of this work may be summarized as follows:

(a) The removal of restrictions on building independent pipelines and storage facilities is likely to have significant benefits, especially if the electricity sector is liberalized. It is also likely to increase the efficiency of operation of the European pipeline network. Continuing such restrictions has few, if any, benefits.

(b) TPA for power plants and large industrial consumers is likely to have significant benefits. The introduction of TPA is also likely to have some benefits in improving the operating efficiency of the network.

(c) There are problems with a potential flow of economic rent outside the Community under TPA because of the uncompetitive nature of the upstream, and there is a risk that some efficiency gains will flow upstream rather than to the consumer. This needs to be addressed by additional policy measures to capture the major benefits of liberalization for all consumers. For example, this could be achieved by fiscal measures. However, retention of the existing market structure, in the belief that concentration of buyer power will balance that of the producers, is unlikely to be a satisfactory policy, as it is very unlikely to produce benefits for consumers.

(d) Increasing the number of gas suppliers to the EU would be extremely beneficial, but will be difficult to achieve.

APPENDIX A

Electricity

A1. Other issues related to the single market in electricity

There is a range of issues related to the completion of the single market in energy which have been treated only briefly in the main body of the report, in order to keep the analysis focused and concise. These issues are discussed further here.

A1.1. Need to avoid cross-subsidization

In the publicly owned electricity supply industry in England and Wales prior to privatization, the prices offered to large customers were subsidized. The large customers avoided paying a capacity charge, contributed neither to the subsidy for British Coal nor to the cost of the expensive nuclear power stations, and some paid little or nothing for transmission. The largest customers effectively paid little more than the energy cost of running on imported coal. In April 1991 the subsidy was removed and 10 MW+ customers complained as their prices increased by an average of about 12% in real terms and converged on prices offered to medium size customers.[40] Pool prices have also risen over the period as they have begun to converge to contract prices.

Non-cost-reflective pricing is believed to exist in several countries at present. Discriminatory pricing places generators attempting to enter new markets, who do not have the support of a captive market to bear the costs of cross-subsidization, at a competitive disadvantage. As well as preventing competition, such price distortions may result in a 'subsidy competition' among those who have a franchise market upon which the costs of the subsidy can be borne.

As noted in the main body of this report the removal of a cross-subsidy represents only an initial effect. If competition acts to increase efficiency, the long-term gains from competition should eventually outweigh the removal of the initial cross-subsidy (provided that this subsidy is not too large).

The main purpose of unbundling accounting is to help identify costs so that they can be adequately reflected in tariffs. In a truly unbundled and competitive system in which there is no cross-subsidy from a franchise market, generators have no incentive to price discriminate. It is assumed that price discrimination at the generation and transmission level is much reduced in any nTPA scenario, and eliminated in a TPA scenario. However, some discrimination at the distribution level remains.

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40 In its report on the 'Consequences of Electricity Privatization' (Volume 1, Energy Committee Second Report, Session 1991–92, 26 February 1992, HMSO) the Energy Committee of the House of Commons stated 'we would not support subsidies to very large users at the expense of smaller users'. The Committee furthermore stated that 'it is certainly unacceptable for intensive electricity users in the UK to be disadvantaged by overseas competitors paying unjustifiably low prices. The remedy clearly lies with the European Commission'.

The issue of distribution companies having the right of third party access is relevant here. If the incumbent generator retains exclusive rights to sell to the distribution companies, this gives the potential to exclude competitors from the industrial sector by cross-subsidizing these from the monopoly part of their market. In contrast, if distribution companies also have the right to buy freely, opportunities for this are reduced, because distribution companies will be able to go elsewhere to secure better deals if undue costs are being charged to them. It will be the task of the regulatory authorities to ensure that they have the appropriate incentives to do so, rather than simply passing excess costs through to their customers. Experience in the UK has shown that such incentives are difficult to create, and the solution adopted in the UK, and more rapidly in Sweden, has been to allow all consumers to buy electricity from independent suppliers. This creates competition in all market segments, greatly reducing the potential for cross-subsidy.

A1.2. Issues of property rights associated with TPA

As noted in the report, access on fair terms to the transmission system is a prerequisite for the successful operation of the single market both within a Member State, and even more so between parties in different Member States. Ensuring that access is provided may alter the property rights of the owner of the transmission system:

(a) In some countries (e.g. Germany) owners built lines on the understanding that they would *de facto* be entitled to their sole use, and that the terms on which others used the lines were at the discretion of the owner.
(b) In other countries, however, lines were built as a joint venture between parties (e.g. Sweden), and the parties became used to sharing and accommodating changing requirements to use lines.
(c) There is now a trend in some countries (e.g. UK) that a condition for building or indeed owning a line (provided there is available capacity) is that it has to be a common carrier.

The consequence that some companies fear from a change of property rights is not that the change will affect the value of the line *per se*, because if other parties use it they should pay a reasonable charge for its use. Rather they are concerned that allowing others access on economic terms will affect the competitive positioning – and hence value – of their generating plant. As noted in the main body of this report, control of transmission has in most countries to date provided the means of controlling the generation market.

A1.3. Requirements for effective establishment of TPA

Once the basic property right issues are resolved, achieving the aim of access requires:

(a) prompt and fair terms for connection where there is capacity;
(b) a reasonable price for the use of the wires;
(c) appropriate payments for transmission system operation costs;
(d) a developed settlement system;
(e) effective arbitration.

A1.4. Prompt and fair terms for connection

Transmission system operators should be required to offer terms within a defined and reasonable period where there is capacity, and should be entitled to earn a reasonable return on the assets needed to make a connection into their system. In situations where connections are dedicated for a particular user and do not impact on the system as a whole, the pricing should not be difficult. But there are obvious difficulties in the frequent cases when there are shared assets for which one party may have already paid, or when general system reinforcement is required to enable a generator or customer to connect in a particular location. In such cases the 'depth in the system' to which interactions will be determined and costed has to be defined (in England and Wales the National Grid Company adopts a 'shallow' approach and treats as much of the system as possible as a common service and shared cost).

A1.5. Pricing for use of a transmission system

Economical transport is important to the operation of trading markets. It is important in electricity, but it has unusual complexities, namely:

(a) The system can be highly interactive, with a change in one part affecting operation elsewhere. Costs can vary both over time and on a regional basis due to changes in losses and requirements for reactive power, and to transmission constraints.
(b) Constraints are more binding than in most – if not all – other transport systems, and the consequential cost implications of requiring plants to operate out of merit can be significant.
(c) Electricity transport requires the real time support of ancillary services.

The theory of spot pricing[41] solved the conceptual problem – in principle it is possible to devise continually varying prices at the nodes of a network based on the short run marginal costs of generation and transmission (including a reliability component representing capacity), and the price of 'transmission' between the two points is then the difference between the spot prices at the nodes. Although short run marginal cost based pricing presents many practical problems, in principle transmission pricing should vary on a zonal basis where the zones are delimited by transmission constraints.

Although transmission pricing is important, the conceptual complexity of the issue should not disguise the fact that it is a minor cost component in the total system. Thus, in the first instance access on reasonably fair and prompt terms will be of more importance than sophisticated transmission pricing. In those systems that have been opened for use by third parties tractable pricing methodologies have been found. The UK system, the largest integrated grid presently open to third parties in Europe, adopted a simple revenue cap approach with RPI-x price control. There is regional differentiation of connection charges to encourage capacity to connect in the south of England where it is in short supply.

41 F.C. Schweppe, M.C. Camanis, R.D. Tabors, R.E. Bohn (1988), *Spot pricing of electricity*, Kluwer Academic Publishers.

A1.6. Firm power and difference pricing

Short term security of supply is a critical issue in developing TPA. A generator with a large portfolio of plant has the inherent advantage over a competitor with only one or two plants, of being able to provide firm power, and also the ability to accommodate differences between a contracted take and the amount actually taken. Co-generation, in particular, can be discouraged by charging a high price for standby and top-up power.

Creation of a power pool avoids this problem, and also matches the integrated nature of an electricity system. Alternatively, the main generator can be given the responsibility of balancing the system.

A1.7. Economic despatch

The benefits of the economic despatch of new entrant generators within a system are self-evident. This objective can be achieved either by generators (infeeds from other systems), being 'despatched' by the dominant utility (subject to procedures to ensure fairness), or by some form of pool. TPA does not necessarily require a pool even for trading within a Member State, particularly where there is a dominant monopoly. Still less does TPA require overall EC despatch – provided the interfaces between systems are economically sound, then separate intertrading 'areas' should (in theory) adjust to each other through price signals to provide an overall optimal despatch.

A1.8. Settlement system

In an efficient single market, arrangements will have to be made for an appropriate settlement mechanism to sort out who pays who for what. A settlement system for relatively few parties trading within a Member State should not present significant difficulties. But trading across Member State control areas and transmission constraints will heighten awareness of the issue of transmission system operation costs, and proper arrangements will be crucial for the success of the single market. In practice, bilateral arrangements are likely to be the main mechanism for this.

A1.9. Effective arbitration

The Commission carefully applies the principle of subsidiarity in defining how disputes under the proposed directive (COM(91) 548 final) should be resolved. It states in the General Explanatory Memorandum that Member States will be free to choose how they implement the directive, e.g. whether to set up a regulatory authority or to rely on competition legislation. This approach avoids the charge that the Commission wishes to be seen as a super-regulator, and also avoids suggesting that Member States should appoint special purpose regulators. However, some form of specialized regulation is likely to be necessary, as noted in the main report.

A1.10. Risk and financing new generation plant

Traditionally, companies in continental Europe have an obligation to supply, which implies an obligation to invest. Customers have no choice of supplier, and have to pay for what the undertakings (or their regulator) determines it costs to provide the supply.

Thus the financing of plant is no problem because in Europe (unlike in the USA) the undertakings building plant know they can generally pass their costs through to the customers. Subsequently, plant 'value' to the utilities equals the plant depreciated cost upon which they earn a return. The utility shareholders face little or no financial risk from the possibility of demand not materializing, nor from relative fuel prices altering and rendering facilities less economic and consequently reducing their economic value.

Competitive generation organized in the form of bidding to electric companies for long-term contracts of 15–30 years does not fundamentally alter the deal since, in the absence of retail 'by-pass', there is still cost pass through to final consumers.

The developer bears the construction cost risk and most – if not all – of the performance risk of availability and operations and maintenance costs. Poor operational performance apart, the developer is then paid for the plant's capital cost, and this provision is the basis for financing the project. The developer is also paid for the fuel (but may have an incentive at the margin to buy keenly).

The utility bears the substantial risks of whether demand will be there that requires the output, and of fuel price increases, including the possibility that if the plant's fuel price increases relative to other generators' fuels, then it may run less than planned and so the plant will reduce in value. In turn, the utility is generally able to pass these risks through to its customers in its electricity tariffs via some form of regulatory agreement.

Competitive generation plus competition to supply customers directly breaks the deal and raises questions concerning how new generation facilities will be financed without a captive customer base.

If there is no cost pass through mechanism, a critical issue is whether investors will be prepared to invest in a market environment where competition shifts some of the risks identified above from customers to owners, and consequently raises the investor's financing rate.[42] We have taken the view that because it is simply a risk transfer, it does not raise overall costs (in a market the risk can be passed to those able to bear it most cheaply).

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42 The total risks should remain the same, but the burden of risk shifts from customer to shareholder which increases the shareholders' required cost of capital.

A2. Electricity prices and taxes

Table A2.1. Electricity prices for EU countries, UK pence on the first day of..., 1990 prices (excluding VAT)

Country and load type	1996	1995	1994	1993	1992	1991	1990	1989	Oct-88	Oct-87	Oct-86	Aug-85
Belgium												
3,300 kWh/year		9.68	8.94	9.64	8.40	8.36	9.02	7.92	8.39	9.11	9.59	7.69
100 kW @ 40% LF		5.30	4.89	5.37	4.61	4.50	4.70	NA	NA	4.65	4.72	3.38
10,000 kW @ 80% LF		2.91	2.68	2.97	2.56	2.54	2.70	2.25	2.41	2.65	2.86	2.32
Denmark												
3,300 kWh/year		7.94	7.54	8.53	7.11	7.46	8.31	7.08	6.77	7.04	7.05	5.46
100 kW @ 40% LF		2.91	2.92	3.33	2.85	3.04	3.30	NA	NA	2.57	2.30	2.05
10,000 kW @ 80% LF		2.63	2.53	2.80	2.17	2.33	2.78	1.73	1.38	1.52	1.72	1.90
France												
3,300 kWh/year		8.72	8.48	8.84	7.66	7.48	8.00	6.07	6.39	6.96	7.33	6.21
100 kW @ 40% LF		4.45	4.53	4.76	3.87	3.65	3.72	NA	NA	3.80	4.05	2.97
10,000 kW @ 80% LF		2.85	2.89	3.05	2.50	2.37	2.42	2.02	2.16	2.41	2.55	2.29
Germany												
3,300 kWh/year		9.83	9.19	9.56	8.53	8.52	9.21	7.86	8.36	9.01	8.70	6.68
100 kW @ 40% LF		7.31	7.03	7.35	6.38	6.15	6.87	NA	NA	6.31	6.53	4.80
10,000 kW @ 80% LF		4.74	4.55	4.77	4.14	4.14	4.62	3.70	7.64	4.20	NA	3.31
Greece												
3,300 kWh/year		3.06	3.16	3.98	4.51	4.50	5.74	5.84	6.89	8.21	NA	NA
100 kW @ 40% LF		2.19	2.34	2.89	3.20	3.24	4.12	NA	NA	5.35	NA	NA
10,000 kW @ 80% LF		1.49	1.64	2.03	2.25	2.48	3.15	3.09	3.64	4.10	NA	NA
Ireland												
3,300 kWh/year		6.51	6.45	7.43	6.39	6.69	7.41	6.66	7.05	8.06	9.12	8.13
100 kW @ 40% LF		4.68	4.47	5.07	4.63	4.71	5.25	NA	NA	5.83	6.58	5.73
10,000 kW @ 80% LF		3.00	2.87	3.25	2.97	3.02	3.37	2.86	3.07	3.75	4.62	4.45
Italy												
3,300 kWh/year		7.70	8.14	7.35	8.04	7.61	7.82	8.95	9.52	11.15	12.16	11.52
100 kW @ 40% LF		NA	NA	5.99	6.59	6.53	6.56	NA	NA	6.48	6.72	6.68
10,000 kW @ 80% LF		NA	NA	3.16	3.34	2.95	3.34	2.49	2.65	3.12	2.81	3.56
Luxembourg												
3,300 kWh/year		8.58	8.09	8.60	7.48	7.45	8.24	7.20	7.54	8.10	8.28	7.19
100 kW @ 40% LF		NA	5.76	6.11	5.10	4.84	5.20	NA	NA	5.24	5.01	3.78
10,000 kW @ 80% LF		NA	3.44	3.67	3.22	3.02	3.29	2.57	2.80	3.46	3.31	2.67
Netherlands												
3,300 kWh/year		6.21	5.99	6.25	5.36	5.52	6.46	4.97	5.10	5.74	5.70	5.77
100 kW @ 40% LF		3.41	3.56	3.65	3.01	3.22	3.59	NA	NA	3.45	3.40	3.65
10,000 kW @ 80% LF		2.74	2.48	2.60	2.16	2.32	2.62	1.88	1.94	2.46	2.17	3.07
Portugal												
3,300 kWh/year		7.53	7.45	8.92	7.35	6.95	7.26	6.92	7.87	8.95	9.70	NA
100 kW @ 40% LF*		4.31	4.51	5.65	4.90	4.65	4.86	NA	NA	6.42	7.13	NA
10,000 kW @ 80% LF*		3.31	3.48	4.36	3.79	3.63	3.88	3.75	4.26	5.02	5.56	NA
Spain												
3,300 kWh/year		7.56	12.49	9.24	8.93	8.99	8.73	7.75	8.10	8.42	8.42	NA
100 kW @ 40% LF		4.31	7.69	5.87	5.87	5.99	5.69	NA	NA	4.94	5.10	NA
10,000 kW @ 80% LF		3.06	5.47	4.18	4.18	4.19	4.13	3.51	3.57	3.70	3.87	NA
UK												
3,300 kWh/year		7.26	7.81	8.06	7.99	7.41	7.36	7.38	7.95	7.77	7.92	8.08
100 kW @ 40% LF		4.10	4.35	4.52	4.60	4.52	4.97	NA	NA	5.19	5.31	5.58
10,000 kW @ 80% LF		3.12	3.31	3.41	3.46	3.45	3.68	3.59	3.76	3.73	3.90	4.36

Industrial prices
Domestic prices

* deflated using CPI

Table A2.2. Electricity prices for EU countries, local currencies on the first day of..., 1990 prices

Country and load type	1996	1995	1994	1993	1992	1991	1990	1989	Oct-88	Oct-87	Oct-86	Aug-85
Belgium												
3,300 kWh/year		6.06	6.01	6.02	5.92	6.03	6.31	6.43	6.73	6.80	7.00	7.29
100 kW @ 40% LF		3.32	3.29	3.35	3.25	3.25	3.29	NA	NA	3.47	3.45	3.20
10,000 kW @ 80% LF		1.82	1.80	1.86	1.81	1.83	1.89	1.83	1.94	1.98	2.09	2.20
Denmark												
3,300 kWh/year		100.79	101.02	108.08	104.78	106.93	113.90	112.68	105.60	103.60	99.66	98.12
100 kW @ 40% LF		36.97	39.08	42.23	42.02	43.55	45.17	NA	NA	37.82	32.52	36.92
10,000 kW @ 80% LF		33.44	33.92	35.48	32.03	33.40	38.13	27.58	21.51	22.38	24.24	34.10
France												
3,300 kWh/year		89.43	91.01	90.85	91.16	90.50	92.40	81.78	84.58	84.94	86.20	90.55
100 kW @ 40% LF		45.64	48.56	48.91	46.11	44.22	42.91	NA	NA	46.42	47.67	43.22
10,000 kW @ 80% LF		29.22	31.04	31.37	29.77	28.68	27.91	27.14	28.64	29.43	29.94	33.30
Germany												
3,300 kWh/year		28.04	27.78	27.58	28.12	28.70	29.51	29.34	30.80	31.31	29.54	30.29
100 kW @ 40% LF		20.86	21.24	21.22	21.04	20.71	22.01	NA	NA	21.94	22.18	21.78
10,000 kW @ 80% LF		13.53	13.76	13.76	13.64	13.95	14.79	13.81	28.16	14.59	NA	15.01
Greece												
3,300 kWh/year		14.05	14.21	15.76	18.04	16.59	17.39	18.52	21.08	22.96	23.89	21.39
100 kW @ 40% LF		10.05	10.52	11.44	12.80	11.96	12.46	NA	NA	14.95	16.51	15.30
10,000 kW @ 80% LF		6.85	7.39	8.04	8.99	9.16	9.54	9.79	11.12	11.46	12.66	11.71
Ireland												
3,300 kWh/year		7.54	7.74	7.91	7.80	8.09	8.14	8.41	8.75	8.94	9.76	10.16
100 kW @ 40% LF		5.42	5.36	5.40	5.65	5.70	5.77	NA	NA	6.47	7.04	7.16
10,000 kW @ 80% LF		3.47	3.44	3.46	3.62	3.66	3.70	3.62	3.82	4.17	4.95	5.56
Italy												
3,300 kWh/year		214.64	226.52	180.25	190.15	182.41	177.40	232.37	246.83	263.98	270.06	330.14
100 kW @ 40% LF		NA	NA	146.82	155.87	156.46	148.90	NA	NA	153.41	149.21	185.46
10,000 kW @ 80% LF		NA	NA	77.38	78.96	70.63	75.80	64.55	68.69	73.91	62.34	98.72
Luxembourg												
3,300 kWh/year		4.55	4.60	4.60	4.65	4.74	5.09	5.17	5.34	5.34	5.34	6.02
100 kW @ 40% LF		NA	3.28	3.27	3.18	3.08	3.21	NA	NA	3.45	3.23	3.17
10,000 kW @ 80% LF		NA	1.96	1.97	2.00	1.92	2.03	1.84	1.98	2.28	2.13	2.24
Netherlands												
3,300 kWh/year		20.42	20.86	20.88	21.05	22.11	24.65	22.51	22.74	24.11	23.52	31.14
100 kW @ 40% LF		11.23	12.41	12.19	11.81	12.90	13.70	NA	NA	14.49	14.03	19.67
10,000 kW @ 80% LF		9.01	8.65	8.70	8.48	9.29	10.00	8.49	8.64	10.31	8.94	16.59
Portugal												
3,300 kWh/year		19.73	20.49	20.87	20.05	19.50	19.21	19.91	22.43	22.75	22.50	22.02
100 kW @ 40% LF*		11.30	12.41	13.21	13.38	13.03	12.86	NA	NA	16.32	16.53	16.21
10,000 kW @ 80% LF*		8.69	9.58	10.21	10.34	10.19	10.26	10.78	12.15	12.76	12.91	13.94
Spain												
3,300 kWh/year		18.52	18.65	18.88	18.57	18.85	17.64	18.03	19.26	18.95	18.40	18.54
100 kW @ 40% LF		10.56	11.48	12.00	12.21	12.54	11.49	NA	NA	11.12	11.15	11.07
10,000 kW @ 80% LF		7.51	8.17	8.54	8.70	8.79	8.34	8.16	8.50	8.33	8.45	8.76
UK												
3,300 kWh/year		7.89	7.81	8.06	7.99	7.41	7.36	7.38	7.95	7.77	7.92	8.08
100 kW @ 40% LF		4.98	5.27	5.48	5.58	5.31	4.97	NA	NA	5.19	5.31	5.58
10,000 kW @ 80% LF		3.78	4.02	4.13	4.19	4.06	3.68	3.59	3.76	3.73	3.90	4.36

Industrial prices
Domestic prices

* deflated using CPI

Table A2.3. Electricity prices for EU countries: local currencies on the first day of ..., current prices

Local currencies on the first day of the year, current prices

Country and load type	1996	1995	1994	1993	1992	1991	1990	1989	Oct-88	Oct-87	Oct-86	Aug-85
Belgium												
3,300 kWh/year		6.84	6.68	6.54	6.26	6.22	6.31	6.16	6.1	6.1	6.18	6.35
100 kW @ 40% LF		3.37	3.27	3.29	3.22	3.21	3.29	NA	NA	3.21	3.35	3.52
10,000 kW @ 80% LF		1.85	1.79	1.82	1.79	1.81	1.89	1.82	1.82	1.83	2.03	2.42
Denmark												
3,300 kWh/year		111	109.1	114.46	109.5	109.5	113.9	109.75	98.21	92.16	85.28	80.97
100 kW @ 40% LF		38.24	39.37	42.27	42.27	44.12	45.17	NA	NA	34.01	28.95	33.88
10,000 kW @ 80% LF		34.59	34.17	35.52	32.22	33.83	38.13	27.22	20.13	20.13	21.58	31.29
France												
3,300 kWh/year		99.84	99.84	98.03	96.36	93.4	92.4	79.08	79.08	77.3	75.91	77.82
100 kW @ 40% LF		46.18	46.33	46.17	44.77	43.65	42.91	NA	NA	42.34	43.4	40.48
10,000 kW @ 80% LF		29.56	29.61	29.61	28.91	28.31	27.91	27.49	27.49	26.85	27.26	31.19
Germany												
3,300 kWh/year		32.87	32.06	30.89	30.26	29.7	29.51	28.58	29.2	29.3	27.59	28.32
100 kW @ 40% LF		22.15	22.17	22.01	21.84	21.21	22.01	NA	NA	20.65	21.4	21.55
10,000 kW @ 80% LF		14.36	14.37	14.27	14.16	14.28	14.79	13.58	26.84	13.73	NA	14.85
Greece												
3,300 kWh/year		27.02	24.97	24.97	24.97	19.82	17.39	15.39	15.39	14.77	13.2	9.61
100 kW @ 40% LF		17.14	16.64	16.64	16.64	13.96	12.46	NA	NA	10.4	10.52	8.27
10,000 kW @ 80% LF		11.69	11.69	11.69	11.69	10.69	9.54	8.45	8.45	7.97	8.07	6.33
Ireland												
3,300 kWh/year		8.54	8.54	8.54	8.3	8.35	8.14	8.14	8.14	8.14	8.615	8.64
100 kW @ 40% LF		5.77	5.77	5.77	5.77	5.77	5.77	NA	NA	6.06	6.55	6.81
10,000 kW @ 80% LF		3.7	3.7	3.7	3.7	3.7	3.7	3.72	3.72	3.9	4.6	5.29
Italy												
3,300 kWh/year		275	275	210.35	212.4	193.9	177.4	218.2	218.2	222.14	217.02	250.51
100 kW @ 40% LF		182.12	176.01	165.61	167.4	164.6	148.9	NA	NA	128.19	121.49	152.315
10,000 kW @ 80% LF		98.04	93.19	87.29	84.8	74.3	75.8	60.1	60.1	61.76	50.76	81.08
Luxembourg												
3,300 kWh/year		5.22	5.18	5.07	4.95	4.89	5.09	4.98	4.98	4.91	4.91	5.52
100 kW @ 40% LF		3.11	3.11	3.06	3.01	3	3.21	NA	NA	3.19	3.19	3.21
10,000 kW @ 80% LF		1.95	1.86	1.84	1.9	1.87	2.03	1.88	1.88	2.11	2.11	2.27
Netherlands												
3,300 kWh/year		23.3	23.4	22.8	22.4	22.8	24.65	21.97	21.97	23.13	22.72	30.05
100 kW @ 40% LF		12.1	13.2	12.9	12.4	13.2	13.7	NA	NA	13.77	13.5	19.45
10,000 kW @ 80% LF		9.7	9.2	9.2	8.9	9.5	10	8.41	8.26	9.8	8.595	16.4
Portugal												
3,300 kWh/year		27.86	27.86	27.05	24.32	21.72	19.21	17.56	17.56	16.26	14.7	12.88
100 kW @ 40% LF		15.95	16.88	17.12	16.23	14.52	12.86	NA	NA	11.66	10.8	9.48
10,000 kW @ 80% LF		12.27	13.03	13.23	12.54	11.35	10.26	9.51	9.51	9.12	8.43	8.15
Spain												
3,300 kWh/year		23.82	22.92	22.15	20.83	19.96	17.64	16.89	16.89	15.86	14.63	13.55
100 kW @ 40% LF		12.41	12.63	12.66	12.56	12.73	11.49	NA	NA	10.15	10.09	9.93
10,000 kW @ 80% LF		8.82	8.99	9.01	8.95	8.92	8.34	7.99	7.99	7.61	7.65	7.86
UK												
3,300 kWh/year		9.33	8.93	8.99	8.772	7.85	7.36	6.735	6.735	6.27	6.138	6.056
100 kW @ 40% LF		6	6.1	6.192	6.066	5.6	4.97	NA	NA	4.46	4.394	4.424
10,000 kW @ 80% LF		4.56	4.65	4.672	4.556	4.284	3.68	3.377	3.38	3.21	3.224	3.458

Industrial prices	Including all taxes except VAT.
Domestic prices	Including all taxes and VAT.

Table A2.4. Domestic electricity prices and taxes

Electricity taxes in the EU Tariffs for 100 kWh (1994-1) **Category**		Prices (ECU) Households D A (annual cons. kWh 600)			Prices (ECU) Households D B (annual cons. kWh 1200)			Prices (ECU) Households D C (annual cons. kWh 3500)			Prices (ECU) Households D D (annual cons. kWh 7500)			Prices (ECU) Households D E (annual cons. kWh 2000)		
Country	**Region**	VAT	Other taxes	Total taxes	VAT	Other taxes	Total taxes	VAT	Other taxes	Total taxes	VAT	Other taxes	Total taxes	VAT	Other taxes	Total taxes
Belgium	National territory *	3.69	0.15	3.84	3.34	0.15	3.49	2.38	0.15	2.53	2.16	0.15	2.31	1.37	0.14	1.51
Denmark	National territory	4.56	5.32	9.88	3.56	5.32	8.88	2.89	5.32	8.21	2.70	5.32	8.02	2.40	4.94	7.34
Germany	Hamburg	3.63	2.20	5.83	2.89	1.62	4.51	2.16	1.21	3.37	1.96	1.10	3.06	1.18	0.66	1.84
	Hanover	2.81	1.54	4.35	2.38	1.32	3.70	1.98	1.08	3.06	1.88	1.03	2.91	1.12	0.61	1.73
	Dusseldorf	3.09	1.72	4.81	2.55	1.41	3.96	2.15	1.20	3.35	1.99	1.10	3.09	1.12	0.62	1.74
	Frankfurt am Main	2.68	1.35	4.03	2.39	1.20	3.59	1.96	1.00	2.96	1.88	0.95	2.83	1.02	0.51	1.53
	Stuttgart	4.04	1.96	6.00	2.96	1.44	4.40	2.05	1.00	3.05	1.84	0.89	2.73	1.05	0.51	1.56
	Munich	2.94	1.49	4.43	2.73	1.38	4.11	2.32	1.17	3.49	2.26	1.14	3.40	1.25	0.63	1.88
	Western zone	3.30	1.83	5.13	2.44	1.37	3.81	1.83	1.02	2.85	1.63	0.91	2.54	1.04	0.57	1.61
	Southern zone	4.51	2.28	6.79	3.27	1.65	4.92	2.28	1.15	3.43	2.04	1.03	3.07	1.19	0.60	1.79
	Erfurt	3.24	-	3.24	2.50	-	2.50	1.85	-	1.85	1.73	-	1.73	1.04	-	1.04
	Leipzig	3.03	-	3.03	2.25	-	2.25	1.68	-	1.68	1.50	-	1.50	0.93	-	0.93
	Rostock	2.97	-	2.97	2.41	-	2.41	1.96	-	1.96	1.86	-	1.86	1.06	-	1.06
Greece	Athens *	1.37	-	1.37	1.31	-	1.31	1.15	-	1.15	1.19	-	1.19	0.87	-	0.87
Spain	Madrid *	2.03	-	2.03	2.03	-	2.03	1.59	-	1.59	1.46	-	1.46	1.04	-	1.04
France	Lille	2.35	1.33	3.68	2.21	1.16	3.37	1.72	1.00	2.72	1.70	0.95	2.65	1.35	0.77	2.12
	Paris	2.37	1.46	3.83	2.24	1.27	3.51	1.74	1.10	2.84	1.72	1.05	2.77	1.38	0.84	2.22
	Marseille	2.35	1.33	3.68	2.21	1.16	3.37	1.72	1.00	2.72	1.70	0.95	2.65	1.35	0.77	2.12
	Lyon	2.35	1.33	3.68	2.21	1.16	3.37	1.72	1.00	2.72	1.70	0.95	2.65	1.35	0.77	2.12
	Toulouse	2.35	1.33	3.68	2.21	1.16	3.37	1.72	1.00	2.72	1.70	0.95	2.65	1.35	0.77	2.12
	Strasbourg	2.18	0.44	2.62	2.07	0.39	2.46	1.59	0.34	1.93	1.58	0.32	1.90	1.27	0.25	1.52
Ireland	Dublin	1.60	-	1.60	1.35	-	1.35	0.94	-	0.94	0.91	-	0.91	0.62	-	0.62
Italy	North and centre	0.57	-	0.57	0.65	-	0.65	1.75	2.21	3.96	1.62	2.21	3.83	-	-	-
	South and Islands	0.57	-	0.57	0.65	-	0.65	1.75	2.09	3.84	1.61	2.10	3.71	-	-	-
	National territory	0.56	1.15	1.71	0.63	0.95	1.58	1.74	3.34	5.08	1.60	3.34	4.94	-	-	-
Luxembourg	Grand Duchy	1.24	-	1.24	0.93	-	0.93	0.62	-	0.62	0.60	-	0.60	0.41	-	0.41
Netherlands	Rotterdam	2.51	-	2.51	2.08	-	2.08	1.63	-	1.63	1.51	-	1.51	1.06	-	1.06
	North Holland	2.14	-	2.14	1.75	-	1.75	1.45	-	1.45	1.37	-	1.37	0.99	-	0.99
	North Brabant	2.20	-	2.20	1.73	-	1.73	1.32	-	1.32	1.20	-	1.20	0.90	-	0.90
Portugal	Lisbon *	0.64	0.10	0.74	0.73	0.05	0.78	0.63	0.02	0.65	0.56	0.01	0.57	0.41	-	0.41
	S. Miguel Acores	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UK	London	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Glasgow	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Leeds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Birmingham	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Source: Electricity prices 1990-94, Eurostat, 1994.

* Standard National Tariff.

Table A2.5. Industrial electricity prices and taxes

Electricity taxes in the EU — Tariffs for 100 kWh (1994-1)

Category		Prices (ECU) Industry I A (annual cons. kWh 30,000)			Prices (ECU) Industry I B (annual cons. kWh 50,000)			Prices (ECU) Industry I C (annual cons. kWh 160,000)		
Country	**Region**	VAT	Other tax	Total tax	VAT	Other tax	Total tax	VAT	Other tax	Total tax
Belgium	National territory *	2.87	-	2.87	2.85	-	2.85	2.36	-	2.36
Denmark	National territory	2.57	0.67	3.24	2.49	0.66	3.15	2.50	0.66	3.16
Germany	Hamburg	3.04	1.71	4.75	3.04	1.71	4.75	2.57	1.45	4.02
	Hanover	2.84	1.57	4.41	2.81	1.54	4.35	2.20	1.21	3.41
	Dusseldorf	4.61	2.56	7.17	2.97	1.65	4.62	2.28	1.26	3.54
	Frankfurt am Main	3.34	1.69	5.03	3.32	1.67	4.99	2.29	1.16	3.45
	Stuttgart	3.13	1.52	4.65	3.05	1.49	4.54	2.34	1.15	3.49
	Munich	3.27	1.65	4.92	3.23	1.64	4.87	2.11	1.06	3.17
	Western Zone	2.60	1.45	4.05	2.52	1.40	3.92	2.15	1.19	3.34
	Southern Zone	2.90	1.46	4.36	2.86	1.45	4.31	2.49	1.25	3.74
	Erfurt	2.80	-	2.80	2.77	-	2.77	2.15	-	2.15
	Leipzig	2.29	-	2.29	2.24	-	2.24	2.09	-	2.09
	Rostock	2.87	-	2.87	2.87	-	2.87	2.60	-	2.60
Greece	Athens *	1.56	-	1.56	1.55	-	1.55	1.43	-	1.43
Spain	Madrid *	1.76	-	1.76	1.76	-	1.76	1.41	-	1.41
France	Lille	2.10	0.98	3.08	1.98	0.37	2.35	1.83	0.34	2.17
	Paris	2.11	1.08	3.19	1.99	0.40	2.39	1.83	0.38	2.21
	Marseille	-	-	-	-	-	-	-	-	-
	Lyon	2.10	0.98	3.08	1.98	0.37	2.35	1.83	0.34	2.17
	Toulouse	-	-	-	-	-	-	-	-	-
	Strasbourg	1.97	0.33	2.30	1.93	0.12	2.05	1.78	0.12	1.90
Ireland	Dublin	1.63	-	1.63	1.61	-	1.61	1.29	-	1.29
Italy	North and Centre	1.47	1.61	3.08	1.28	1.79	3.07	1.03	1.80	2.83
	South and Islands	1.22	1.49	2.71	1.27	1.68	2.95	1.03	1.68	2.71
	National Territory	1.44	2.80	4.24	1.25	2.49	3.74	1.01	2.49	3.50
Luxembourg	Grand Duchy **	0.83	-	0.83	0.84	-	0.84	0.64	-	0.64
Netherlands	Rotterdam	1.83	-	1.83	1.84	-	1.84	1.99	-	1.99
	North Holland	1.57	-	1.57	1.57	-	1.57	1.54	-	1.54
	North Brabant	1.39	-	1.39	1.43	-	1.43	1.64	-	1.64
Portugal	Lisbon *	0.65	0.01	0.66	0.67	-	0.67	0.55	-	0.55
	S. Miguel Acores	0.64	-	0.64	0.64	-	0.64	0.58	-	0.58
UK	London	1.81	-	1.81	1.77	-	1.77	1.98	-	1.98
	Glasgow	2.19	-	2.19	2.12	-	2.12	2.05	-	2.05
	Leeds	1.81	-	1.81	2.20	-	2.20	1.72	-	1.72
	Birmingham	1.81	-	1.81	1.78	-	1.78	1.58	-	1.58

Category		Prices (ECU) Industry I D (annual cons. MWh 1,250)			Prices (ECU) Industry I E (annual cons. MWh 2,000)			Prices (ECU) Industry I F (annual cons. MWh 10,000)		
Country	**Region**	VAT	Other tax	Total tax	VAT	Other tax	Total tax	VAT	Other taxes	Total taxes
Belgium	National territory *	1.76	-	1.76	1.49	-	1.49	1.41	-	1.41
Denmark	National territory	2.45	0.66	3.11	2.43	0.66	3.09	2.42	0.66	3.08
Germany	Hamburg	2.07	1.17	3.24	1.66	0.93	2.59	1.66	0.93	2.59
	Hanover	1.83	1.01	2.84	1.54	0.85	2.39	1.53	0.84	2.37
	Dusseldorf	1.81	1.01	2.82	1.61	0.89	2.50	1.49	0.83	2.32
	Frankfurt am Main	1.77	0.90	2.67	1.45	0.74	2.19	1.39	0.71	2.10
	Stuttgart	1.89	0.92	2.81	1.56	0.76	2.32	1.49	0.73	2.22
	Munich	1.68	0.86	2.54	1.38	0.70	2.08	1.36	0.68	2.04
	Western Zone	1.73	0.96	2.69	1.53	0.84	2.37	1.40	0.78	2.18
	Southern Zone	1.62	0.82	2.44	1.36	0.69	2.05	1.33	0.67	2.00
	Erfurt	1.60	-	1.60	1.36	-	1.36	1.35	-	1.35
	Leipzig	1.70	-	1.70	1.43	-	1.43	1.32	-	1.32
	Rostock	1.69	-	1.69	1.38	-	1.38	1.38	-	1.38
Greece	Athens *	1.14	-	1.14	1.05	-	1.05	1.05	-	1.05
Spain	Madrid *	1.29	-	1.29	1.15	-	1.15	1.08	-	1.08
France	Lille	1.46	-	1.46	1.21	-	1.21	1.21	-	1.21
	Paris	1.46	-	1.46	1.21	-	1.21	1.21	-	1.21
	Marseille	-	-	-	-	-	-	-	-	-
	Lyon	1.46	-	1.46	1.21	-	1.21	1.21	-	1.21
	Toulouse	-	-	-	-	-	-	-	-	-
	Strasbourg	1.46	-	1.46	1.21	-	1.21	1.21	-	1.21
Ireland	Dublin	0.99	-	0.99	0.81	-	0.81	0.76	-	0.76
Italy	North and Centre	0.98	1.79	2.77	0.84	1.80	2.64	0.76	0.98	1.74
	South and Islands	0.96	1.68	2.64	0.83	1.69	2.52	0.76	0.90	1.66
	National Territory	0.95	2.49	3.44	0.82	2.49	3.31	0.75	1.70	2.45
Luxembourg	Grand Duchy **	0.53	-	0.53	0.45	-	0.45	0.35	-	0.35
Netherlands	Rotterdam	1.55	-	1.55	1.28	-	1.28	1.08	-	1.08
	North Holland	1.10	-	1.10	0.94	-	0.94	0.92	-	0.92
	North Brabant	1.08	-	1.08	0.91	-	0.91	0.91	-	0.91
Portugal	Lisbon *	0.48	-	0.48	0.42	-	0.42	0.42	-	0.42
	S. Miguel Acores	0.52	-	0.52	0.48	-	0.48	0.47	-	0.47
UK	London	1.40	-	1.40	1.22	-	1.22	0.98	-	0.98
	Glasgow	1.63	-	1.63	1.38	-	1.38	-	-	-
	Leeds	1.29	-	1.29	1.18	-	1.18	1.09	-	1.09
	Birmingham	1.29	-	1.29	1.20	-	1.20	0.97	-	0.97

Category		Prices (ECU) Industry I G (annual cons. MWh 24,000)			Prices (ECU) Industry I H (annual cons. MWh 50,000)			Prices (ECU) Industry I I (annual cons. MWh 70,000)		
Country	**Region**	VAT	Other taxes	Total taxes	VAT	Other taxes	Total taxes	VAT	Other taxes	Total taxes
Belgium	National territory *	1.16	-	1.16	1.01	-	1.01	0.87	-	0.87
Denmark	National territory	2.33	0.66	2.99	2.30	0.67	2.97	2.27	0.67	2.94
Germany	Hamburg	1.38	0.78	2.16	1.50	0.84	2.34	1.29	0.73	2.02
	Hanover	1.28	0.71	1.99	1.34	0.74	2.08	1.19	0.66	1.85
	Dusseldorf	1.18	0.67	1.85	1.30	0.73	2.03	1.08	0.60	1.68
	Frankfurt am Main	1.19	0.61	1.80	1.27	0.63	1.90	1.13	0.58	1.71
	Stuttgart	1.24	0.61	1.85	1.29	0.62	1.91	1.12	0.54	1.66
	Munich	1.19	0.61	1.80	1.25	0.62	1.87	1.14	0.58	1.72
	Western Zone	1.08	0.61	1.69	1.18	0.65	1.83	0.96	0.54	1.50
	Southern Zone	1.17	0.58	1.75	1.19	0.60	1.79	1.10	0.56	1.66
	Erfurt	1.16	-	1.16	1.24	-	1.24	1.11	-	1.11
	Leipzig	1.06	-	1.06	1.14	-	1.14	0.96	-	0.96
	Rostock	1.16	-	1.16	1.12	-	1.12	0.96	-	0.96
Greece	Athens *	0.89	-	0.89	0.85	-	0.85	0.74	-	0.74
Spain	Madrid *	0.97	-	0.97	0.97	-	0.97	0.87	-	0.87
France	Lille	1.05	-	1.05	0.95	-	0.95	0.85	-	0.85
	Paris	1.05	-	1.05	0.95	-	0.95	0.85	-	0.85
	Marseille	-	-	-	-	-	-	-	-	-
	Lyon	1.05	-	1.05	0.95	-	0.95	0.85	-	0.85
	Toulouse	-	-	-	-	-	-	-	-	-
	Strasbourg	1.05	-	1.05	0.95	-	0.95	0.85	-	0.85
Ireland	Dublin	0.65	-	0.65	0.65	-	0.65	0.59	-	0.59
Italy	North and Centre	0.57	0.47	1.04	0.58	0.40	0.98	0.46	0.39	0.85
	South and Islands	0.57	0.39	0.96	0.58	0.33	0.91	0.46	0.32	0.78
	National Territory	0.58	1.15	1.73	0.55	1.03	1.58	0.46	0.97	1.43
Luxembourg	Grand Duchy **	0.28	-	0.28	0.29	-	0.29	0.25	-	0.25
Netherlands	Rotterdam	0.81	-	0.81	0.86	-	0.86	0.76	-	0.76
	North Holland	0.78	-	0.78	0.82	-	0.82	0.73	-	0.73
	North Brabant	0.78	-	0.78	0.82	-	0.82	0.74	-	0.74
Portugal	Lisbon *	0.35	-	0.35	0.32	-	0.32	0.29	-	0.29
	S. Miguel Acores	-	-	-	-	-	-	-	-	-
UK	London	0.98	-	0.98	0.88	-	0.88	1.00	-	1.00
	Glasgow	-	-	-	-	-	-	-	-	-
	Leeds	1.01	-	1.01	-	-	-	-	-	-
	Birmingham	0.91	-	0.91	-	-	-	-	-	-

Source: *Electricity Prices 1990-94*, Eurostat, 1994

* Standard National Tariff

** 50 %

A3. Fuel mix

Figure A3.1. Electricity generation by fuel for the EU-15, 1960–93

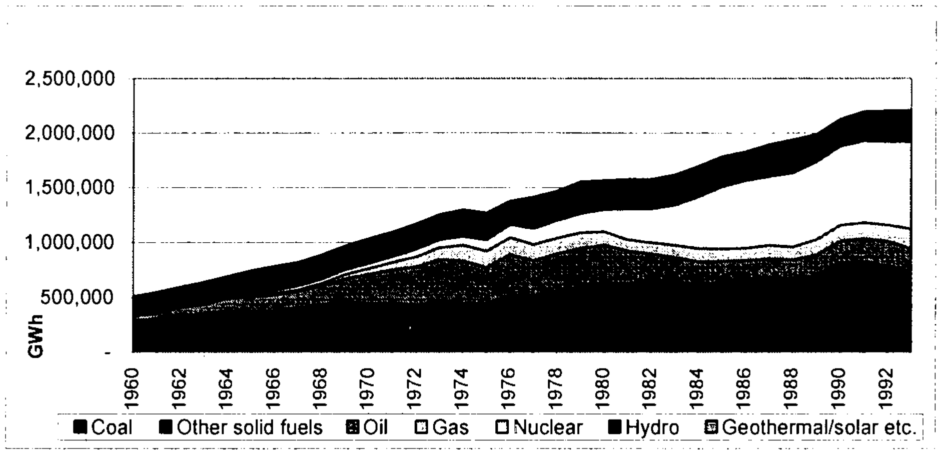


Table A3.1. Electricity generation by fuel for the EU-15 (1995 membership), 1960–93

GWh	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969
Coal	284480	306149	337672	350468	379042	378504	377022	400659	429714	455264
Other solid fuels	1774	1794	1726	2336	2610	2824	3982	4594	5362	5920
Oil	43002	54116	70500	80897	108831	125178	140370	149716	170430	211625
Gas	7691	9219	10394	10102	10220	9945	13593	16837	25421	36708
Nuclear	2370	2862	4297	7210	11374	19833	26002	30719	34266	41924
Hydro	169945	173055	171694	188757	179601	205234	224157	216675	221386	217150
Geothermal/solar etc.	2104	2292	2346	2427	2527	2576	2633	2818	3113	3229
Total	511366	549487	598629	642197	694205	744094	787759	822018	889692	971820

GWh	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Coal	436739	441344	419272	453707	439531	436885	511776	508187	539839	581142
Other solid fuels	9335	9369	9469	10237	10755	10860	12264	12211	14184	15135
Oil	265043	298998	350841	380178	381165	325659	366826	314078	342660	347814
Gas	53345	69564	91556	109711	140810	148120	149950	144446	140352	141285
Nuclear	42333	49079	63286	67475	76700	96815	117458	142188	159344	172564
Hydro	226637	223678	232479	231499	247814	249230	216713	290345	271226	293664
Geothermal/solar etc.	3219	3165	3133	3039	3097	3000	2961	2956	2964	2996
	1036651	1095197	1170036	1255846	1299872	1270569	1377948	1414411	1470569	1554600

GWh	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Coal	616212	612668	630608	640635	577101	629202	649343	664819	652463	671346
Other solid fuels	16967	15923	15341	14966	18054	19184	18882	19133	20961	22162
Oil	340757	290490	250314	208463	226841	179902	166959	169215	166858	194515
Gas	121451	103178	99302	109878	120535	112108	112336	119582	118137	135163
Nuclear	199627	278062	307425	362885	469010	562285	611650	625272	670280	711391
Hydro	265476	272231	269910	277253	283324	282205	268342	293894	308761	249809
Geothermal/solar etc.	3168	3226	3336	3341	3495	3358	3492	3757	3993	4189
	1563658	1575778	1576236	1617421	1698360	1788244	1831004	1895672	1941453	1988575

GWh	1990	1991	1992	1993
Coal	790890	801046	766897	719191
Other solid fuels	25479	24019	18540	21806
Oil	191780	207782	224412	196365
Gas	146380	144987	145951	184475
Nuclear	720189	747352	759898	794238
Hydro	248928	266787	284174	288366
Geothermal/solar etc.	4500	5381	4947	6260
	2128146	2197354	2204819	2210701

Source: IEA statistics: energy balances of OECD countries.

Table A3.2. Percentage composition of the inputs used for the production of electricity in the 15 EU Member States (1993)

Country	Coal	Crude oil	Petroleum products	Gas	Nuclear	Hydro	Geotherm. solar etc.	Combust. renew and waste	Total
Austria	15.5	0.0	2.5	25.5	0.0	53.3	0.0	3.2	100.0
Belgium *	24.7	0.0	1.1	9.3	63.0	0.1	0.0	1.8	100.0
Denmark	77.4	0.0	8.3	2.4	0.0	0.0	10.7	1.2	100.0
Finland *	48.9	0.0	2.4	3.8	34.3	7.7	0.0	2.8	100.0
France	5.2	0.0	0.4	0.5	88.6	5.1	0.0	0.2	100.0
Germany	59.0	0.0	1.8	5.4	31.4	1.2	0.0	1.1	100.0
Greece *	75.6	0.0	21.7	0.2	0.0	2.2	0.0	0.3	100.0
Ireland *	55.7	0.0	15.6	26.7	0.0	1.9	0.0	0.0	100.0
Italy *	10.3	0.0	54.9	18.8	0.0	8.3	7.4	0.3	100.0
Luxembourg	71.4	0.0	9.5	4.8	0.0	4.8	0.0	9.5	100.0
Netherlands *	32.6	0.0	4.4	54.3	6.4	0.1	0.1	2.0	100.0
Portugal *	43.9	0.0	40.5	0.0	0.0	12.9	0.0	2.7	100.0
Spain *	42.5	0.0	6.9	0.5	43.5	6.3	0.0	0.3	100.0
Sweden *	3.6	0.0	2.5	1.1	64.3	25.8	0.0	2.7	100.0
United Kingdom	48.9	0.0	7.6	10.9	31.3	0.5	0.0	0.7	100.0

Source: IEA, 'Energy Balances of OECD Countries 1992-1993', Paris, 1995.
* Electricity production includes both electricity and CHP plants.

A4. Input data

Table A4.1. Austria

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		144072	152239	176965	198887	218820	239797	263709
GDP deflator (1985=100)		122.73	135.71	158.45	183.81	213.40	248.04	288.36
Interest rate (%)		9.71	7.48	7.51	7.39	7.40	7.40	7.40
Exchange rate (curr./$)		10.99	11.82	11.19	10.43	9.69	9.08	8.60
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	1907	1907	1907	1907	1907	1907	1907
	Fixed cost ($90/kW)	36	36	36	36	36	36	36
	Variable cost (mills$'90/kWh)	1.58	1.58	1.58	1.58	1.58	1.58	1.58
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1065	1065	1065	1051	1038	1025	1012
	Fixed cost ($90/kW)	40	40	40	39	39	38	38
	Variable cost (mills$'90/kWh)	0.81	0.81	0.81	0.81	0.81	0.81	0.81
	Efficiency rate (%)	40%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1115	1115	1115	1101	1087	1073	1059
	Fixed cost ($90/kW)	42	42	42	41	41	40	40
	Variable cost (mills$'90/kWh)	1.41	1.41	1.41	1.41	1.41	1.41	1.41
	Efficiency rate (%)	39%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1197	1197	1197	1197	1197	1197	1197
	Fixed cost ($90/kW)	72	72	72	72	72	72	72
	Variable cost (mills$'90/kWh)	1.41	1.41	1.41	1.41	1.41	1.41	1.41
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1176	1176	1176	1150	1124	1098	1072
	Fixed cost ($90/kW)	44	44	44	43	42	41	40
	Variable cost (mills$'90/kWh)	1.41	1.41	1.41	1.41	1.41	1.41	1.41
	Efficiency rate (%)	39%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	727	727	727	718	708	699	690
	Fixed cost ($90/kW)	21	21	21	21	21	20	20
	Variable cost (mills$'90/kWh)	1.41	1.41	1.41	1.41	1.41	1.41	1.41
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	307	307	307	307	307	307	307
	Fixed cost ($90/kW)	12	12	12	12	12	12	12
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1503	1503	1503	1393	1292	1229	1198
	Fixed cost ($90/kW)	54	54	54	50	46	44	43
	Variable cost (mills$'90/kWh)	1.67	1.67	1.67	1.67	1.67	1.67	1.67
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		6881	3900	4800	4200	3225	3225	3225
Contracted for intermediate load		2294	1300	1600	1400	1075	1075	1075
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of Imports ($m/kWh)		94	104	119	141	178	223	277
Exports of electricity (GWh)								
Contracted for base load		6466	2700	2400	1650	1650	1650	1650
Contracted for intermediate load		2155	900	800	550	550	550	550
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.2. Belgium

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		170667	176079	200873	220419	241575	261415	280157
GDP deflator (1985=100)		121.80	132.77	151.57	174.20	202.29	234.40	272.72
Interest rate (%)		13.00	10.32	9.76	9.61	9.61	9.61	9.61
Exchange rate (curr./$)		32.15	34.66	32.83	30.60	28.42	26.63	25.23
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2406	2406	2406	2406	2406	2406	2406
	Fixed cost ($90/kW)	43	43	43	43	43	43	43
	Variable cost (mills$'90/kWh)	0.54	0.54	0.54	0.54	0.54	0.54	0.54
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1343	1343	1343	1326	1309	1293	1276
	Fixed cost ($90/kW)	50	50	50	50	49	49	48
	Variable cost (mills$'90/kWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1407	1407	1407	1389	1371	1354	1336
	Fixed cost ($90/kW)	52	52	52	52	51	50	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	37%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1509	1509	1509	1509	1509	1509	1509
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1483	1483	1483	1450	1418	1385	1352
	Fixed cost ($90/kW)	55	55	55	54	53	51	50
	Variable cost (mills$'90/kWh)	1.65	1.65	1.65	1.65	1.65	1.65	1.65
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	917	917	917	905	894	882	871
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	451	451	451	451	451	451	451
	Fixed cost ($90/kW)	17	17	17	17	17	17	17
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1890	1890	1890	1753	1625	1546	1507
	Fixed cost ($90/kW)	68	68	68	63	58	56	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		5848	7000	9700	9700	9700	9700	9700
Contracted for intermediate load		0	0	0	0	0	0	0
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		159	80	90	104	129	158	191
Exports of electricity (GWh)								
Contracted for base load		5720	6000	6000	6000	6000	3000	3000
Contracted for intermediate load		0	0	0	0	0	0	0
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.3. Denmark

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		109901	120526	138704	153995	169190	184265	199344
GDP deflator (1985=100)		126.40	133.52	154.50	180.07	209.85	242.09	277.35
Interest rate (%)		10.80	7.79	8.00	7.88	7.88	7.88	7.88
Exchange rate (curr./$)		6.04	6.47	6.12	5.70	5.30	4.96	4.70
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2405	2405	2405	2405	2405	2405	2405
	Fixed cost ($90/kW)	45	45	45	45	45	45	45
	Variable cost (mills$'90/kWh)	2.91	2.91	2.91	2.91	2.91	2.91	2.91
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1342	1342	1342	1326	1309	1292	1275
	Fixed cost ($90/kW)	50	50	50	50	49	48	48
	Variable cost (mills$'90/kWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1406	1406	1406	1388	1371	1353	1336
	Fixed cost ($90/kW)	52	52	52	52	51	50	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1509	1509	1509	1509	1509	1509	1509
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1479	1479	1479	1446	1413	1381	1348
	Fixed cost ($90/kW)	55	55	55	54	52	51	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	37%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	914	914	914	902	891	879	868
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	387	387	387	387	387	387	387
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1890	1890	1890	1752	1624	1545	1507
	Fixed cost ($90/kW)	68	68	68	63	58	56	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		7349	2000	2000	1900	1500	1500	1500
Contracted for intermediate load		0	300	300	200	100	100	100
Contracted for peak load		1297	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		76	84	96	114	144	181	224
Exports of electricity (GWh)								
Contracted for base load		4138	2500	5000	5000	2500	1000	1000
Contracted for intermediate load		762	500	500	500	500	250	250
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.4. Finland

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		93636	99305	116777	134091	151637	168998	186154
GDP deflator (1985=100)		138.87	149.12	176.42	208.12	245.97	292.58	348.56
Interest rate (%)		11.98	8.18	7.70	7.22	6.96	7.05	7.05
Exchange rate (curr./$)		4.48	5.55	5.45	5.33	5.21	5.12	5.09
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2410	2410	2410	2410	2410	2410	2410
	Fixed cost ($90/kW)	45	45	45	45	45	45	45
	Variable cost (mills$'90/kWh)	4.71	4.71	4.71	4.71	4.71	4.71	4.71
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1345	1345	1345	1328	1311	1295	1278
	Fixed cost ($90/kW)	50	50	50	50	49	49	48
	Variable cost (mills$'90/kWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1409	1409	1409	1391	1373	1356	1338
	Fixed cost ($90/kW)	53	53	53	52	51	51	50
	Variable cost (mills$'90/kWh)	1.83	1.83	1.83	1.83	1.83	1.83	1.83
	Efficiency rate (%)	39%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1512	1512	1512	1512	1512	1512	1512
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1485	1485	1485	1453	1420	1387	1355
	Fixed cost ($90/kW)	55	55	55	54	53	51	50
	Variable cost (mills$'90/kWh)	1.83	1.83	1.83	1.83	1.83	1.83	1.83
	Efficiency rate (%)	39%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	918	918	918	906	895	883	872
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	387	387	387	387	387	387	387
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1898	1898	1898	1760	1632	1552	1514
	Fixed cost ($90/kW)	68	68	68	63	59	56	54
	Variable cost (mills$'90/kWh)	2.11	2.11	2.11	2.11	2.11	2.11	2.11
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		6800	3863	2250	2250	2250	2250	2250
Contracted for intermediate load		2267	1288	750	750	750	750	750
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of Imports ($m/kWh)		48	39	39	40	41	42	42
Exports of Electricity (GWh)								
Contracted for base load		505	375	375	375	375	375	375
Contracted for intermediate load		168	125	125	125	125	125	125
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.5. France

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		1032264	1065073	1219206	1382492	1556930	1721300	1879986
GDP deflator (1985=100)		125.70	131.75	153.36	176.54	203.41	234.67	271.17
Interest rate (%)		16.16	12.05	11.71	11.52	11.52	11.52	11.52
Exchange rate (curr./$)		5.29	5.66	5.33	4.97	4.62	4.33	4.10
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	1744	1744	1744	1744	1744	1744	1744
	Fixed cost ($90/kW)	35	35	35	35	35	35	35
	Variable cost (mills$'90/kWh)	3.30	3.30	3.30	3.30	3.30	3.30	3.30
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1338	1338	1338	1322	1305	1288	1271
	Fixed cost ($90/kW)	50	50	50	50	49	48	48
	Variable cost (mills$'90/kWh)	1.10	1.10	1.10	1.10	1.10	1.10	1.10
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1402	1402	1402	1384	1367	1349	1332
	Fixed cost ($90/kW)	52	52	52	52	51	50	50
	Variable cost (mills$'90/kWh)	1.83	1.83	1.83	1.83	1.83	1.83	1.83
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1508	1508	1508	1508	1508	1508	1508
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1478	1478	1478	1445	1413	1380	1348
	Fixed cost ($90/kW)	55	55	55	54	52	51	50
	Variable cost (mills$'90/kWh)	1.83	1.83	1.83	1.83	1.83	1.83	1.83
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	916	916	916	904	893	882	870
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.83	1.83	1.83	1.83	1.83	1.83	1.83
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	386	386	386	386	386	386	386
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1889	1889	1889	1752	1624	1544	1506
	Fixed cost ($90/kW)	68	68	68	63	58	56	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		3789	2310	3000	3000	3000	3000	3000
Contracted for intermediate load		852	540	720	720	720	720	720
Contracted for peak load		95	150	280	280	280	280	280
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of Imports ($m/kWh)		179	192	234	289	361	447	547
Exports of electricity (GWh)								
Contracted for base load		43892	49050	56850	37500	33000	30000	30000
Contracted for intermediate load		14631	16350	18950	12500	11000	10000	10000
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.6. Germany

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		1481163	1544973	1839409	2097206	2316011	2511244	2707010
GDP deflator (1985=100)		123.50	134.70	154.93	177.90	204.75	235.35	270.13
Interest rate (%)		13.59	10.90	10.94	10.77	10.77	10.77	10.77
Exchange rate (curr./$)		1.56	1.67	1.58	1.47	1.37	1.28	1.22
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2620	2620	2620	2620	2620	2620	2620
	Fixed cost ($90/kW)	49	49	49	49	49	49	49
	Variable cost (mills$'90/kWh)	11.11	11.11	11.11	11.11	11.11	11.11	11.11
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1336	1336	1336	1320	1303	1286	1270
	Fixed cost ($90/kW)	50	50	50	50	49	48	48
	Variable cost (mills$'90/kWh)	0.99	0.99	0.99	0.99	0.99	0.99	0.99
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1400	1400	1400	1382	1365	1347	1330
	Fixed cost ($90/kW)	52	52	52	52	51	50	50
	Variable cost (mills$'90/kWh)	1.79	1.79	1.79	1.79	1.79	1.79	1.79
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1564	1564	1564	1564	1564	1564	1564
	Fixed cost ($90/kW)	58	58	58	58	58	58	58
	Variable cost (mills$'90/kWh)	1.79	1.79	1.79	1.79	1.79	1.79	1.79
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1476	1476	1476	1443	1411	1378	1346
	Fixed cost ($90/kW)	55	55	55	53	52	51	50
	Variable cost (mills$'90/kWh)	1.79	1.79	1.79	1.79	1.79	1.79	1.79
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb.cycle	Investment cost ($90/kW)	914	914	914	903	891	880	869
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.79	1.79	1.79	1.79	1.79	1.79	1.79
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	385	385	385	385	385	385	385
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1886	1886	1886	1749	1621	1542	1504
	Fixed cost ($90/kW)	68	68	68	63	58	55	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	47%	49%	52%	55%	58%
Imports of electricity (GWh)								
Contracted for base load		21310	24375	22500	22500	22500	20625	18375
Contracted for intermediate load		7103	8125	7500	7500	7500	6875	6125
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of Imports ($m/kWh)		235	211	219	231	246	259	270
Exports of electricity (GWh)								
Contracted for base load		25299	24000	15750	13500	13500	12000	12000
Contracted for intermediate load		8433	8000	5250	4500	4500	4000	4000
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.7. Greece

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		32523	32847	37534	42641	48882	55490	63179
GDP deflator (1985=100)		284.40	392.41	578.53	802.89	1098.46	1463.80	1952.53
Interest rate (%)		28.83	22.80	16.21	16.21	16.21	16.21	16.21
Exchange rate (curr./$)		190.71	283.73	343.44	388.37	428.16	465.90	511.64
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2405	2405	2405	2405	2405	2405	2405
	Fixed cost ($90/kW)	45	45	45	45	45	45	45
	Variable cost (mills$'90/kWh)	0.11	0.11	0.11	0.11	0.11	0.11	0.11
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	927	927	927	915	903	892	880
	Fixed cost ($90/kW)	39	39	39	38	38	37	37
	Variable cost (mills$'90/kWh)	0.81	0.81	0.81	0.81	0.81	0.81	0.81
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1406	1406	1406	1388	1371	1353	1336
	Fixed cost ($90/kW)	52	52	52	52	51	50	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1509	1509	1509	1509	1509	1509	1509
	Fixed cost ($90/kW)	46	46	46	46	46	46	46
	Variable cost (mills$'90/kWh)	1.19	1.19	1.19	1.19	1.19	1.19	1.19
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1482	1482	1482	1450	1417	1384	1352
	Fixed cost ($90/kW)	55	55	55	54	53	51	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	916	916	916	905	893	882	870
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	387	387	387	387	387	387	387
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1889	1889	1889	1752	1624	1545	1506
	Fixed cost ($90/kW)	68	68	68	63	58	56	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		0	0	0	0	0	0	0
Contracted for intermediate load		580	736	543	632	640	640	640
Contracted for peak load		387	491	362	421	440	440	440
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		30	39	64	90	119	157	200
Exports of electricity (GWh)								
Contracted for base load		0	0	0	0	0	0	0
Contracted for intermediate load		253	237	380	475	480	480	480
Contracted for peak load		109	102	163	203	200	200	200
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.8. Ireland

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		40218	46819	56046	65576	76099	85279	95239
GDP deflator (1985=100)		120.70	131.82	151.59	174.14	199.36	230.90	266.44
Interest rate (%)		15.31	11.97	11.51	11.33	11.32	11.29	11.22
Exchange rate (curr./$)		0.59	0.68	0.65	0.60	0.56	0.52	0.50
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2417	2417	2417	2417	2417	2417	2417
	Fixed cost ($90/kW)	45	45	45	45	45	45	45
	Variable cost (mills$'90/kWh)	29.90	29.90	29.90	29.90	29.90	29.90	29.90
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1349	1349	1349	1332	1315	1298	1282
	Fixed cost ($90/kW)	51	51	51	50	49	49	48
	Variable cost (mills$'90/kWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1413	1413	1413	1395	1378	1360	1342
	Fixed cost ($90/kW)	53	53	53	52	51	51	50
	Variable cost (mills$'90/kWh)	1.79	1.79	1.79	1.79	1.79	1.79	1.79
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1516	1516	1516	1516	1516	1516	1516
	Fixed cost ($90/kW)	92	92	92	92	92	92	92
	Variable cost (mills$'90/kWh)	1.79	1.79	1.79	1.79	1.79	1.79	1.79
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1490	1490	1490	1457	1424	1391	1359
	Fixed cost ($90/kW)	55	55	55	54	53	52	50
	Variable cost (mills$'90/kWh)	1.79	1.79	1.79	1.79	1.79	1.79	1.79
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	921	921	921	909	898	886	875
	Fixed cost ($90/kW)	27	27	27	27	26	26	26
	Variable cost (mills$'90/kWh)	1.76	1.76	1.76	1.76	1.76	1.76	1.76
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	453	453	453	453	453	453	453
	Fixed cost ($90/kW)	18	18	18	18	18	18	18
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1899	1899	1899	1761	1633	1553	1514
	Fixed cost ($90/kW)	68	68	68	63	59	56	54
	Variable cost (mills$'90/kWh)	2.11	2.11	2.11	2.11	2.11	2.11	2.11
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		0	0	0	0	0	0	0
Contracted for intermediate load		0	0	0	0	0	0	0
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		65	62	76	95	103	109	115
Exports of electricity (GWh)								
Contracted for base load		0	0	0	0	0	0	0
Contracted for intermediate load		0	0	0	0	0	0	0
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.9. Italy

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		805442	829238	944379	1046446	1148597	1260391	1369423
GDP deflator (1985=100)		156.70	165.13	197.50	239.94	291.14	352.40	426.28
Interest rate (%)		15.77	10.05	10.44	9.72	9.73	9.73	9.73
Exchange rate (curr./$)		1232.40	1592.02	1615.65	1581.13	1541.93	1517.22	1509.13
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2401	2401	2401	2401	2401	2401	2401
	Fixed cost ($90/kW)	45	45	45	45	45	45	45
	Variable cost (mills$'90/kWh)	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1340	1340	1340	1323	1307	1290	1273
	Fixed cost ($90/kW)	50	50	50	50	49	48	48
	Variable cost (mills$'90/kWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02
	Efficiency rate (%)	39%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1407	1407	1407	1389	1372	1354	1336
	Fixed cost ($90/kW)	52	52	52	52	51	50	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1510	1510	1510	1510	1510	1510	1510
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1480	1480	1480	1447	1415	1382	1350
	Fixed cost ($90/kW)	55	55	55	54	52	51	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	917	917	917	905	894	882	871
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	386	386	386	386	386	386	386
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1891	1891	1891	1753	1625	1546	1507
	Fixed cost ($90/kW)	68	68	68	63	58	56	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		26955	26250	16500	11250	8000	8000	8000
Contracted for intermediate load		8985	8750	5500	3750	2000	2000	2000
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		164	174	198	223	261	303	348
Exports of electricity (GWh)								
Contracted for base load		517	802	806	810	800	800	800
Contracted for intermediate load		129	201	202	203	160	160	160
Contracted for peak load		0	0	0	0	160	160	160
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.10. The Netherlands

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		281251	292522	333663	372472	414113	451958	490403
GDP deflator (1985=100)		110.30	113.46	128.01	146.13	166.97	190.81	219.42
Interest rate (%)		12.75	9.99	9.84	9.68	9.69	9.69	9.69
Exchange rate (curr./$)		1.76	1.88	1.78	1.66	1.54	1.44	1.37
Discount rate (%, real)		9.00	8.0C	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	1747	1747	1747	1747	1747	1747	1747
	Fixed cost ($90/kW)	35	35	35	35	35	35	35
	Variable cost (mills$'90/kWh)	9.89	9.89	9.89	9.89	9.89	9.89	9.89
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1344	1344	1344	1327	1310	1293	1277
	Fixed cost ($90/kW)	50	50	50	50	49	49	48
	Variable cost (mills$'90/kWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1407	1407	1407	1390	1372	1355	1337
	Fixed cost ($90/kW)	52	52	52	52	51	51	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1510	1510	1510	1510	1510	1510	1510
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1480	1480	1480	1447	1415	1382	1349
	Fixed cost ($90/kW)	55	55	55	54	53	51	50
	Variable cost (mills$'90/kWh)	1.65	1.65	1.65	1.65	1.65	1.65	1.65
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	917	917	917	906	894	883	871
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.65	1.65	1.65	1.65	1.65	1.65	1.65
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	387	387	387	387	387	387	387
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1891	1891	1891	1754	1626	1546	1508
	Fixed cost ($90/kW)	68	68	68	63	58	56	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		7568	9775	13600	11900	6000	6000	6000
Contracted for intermediate load		1336	1725	2400	2100	1440	1440	1440
Contracted for peak load		0	0	0	0	560	560	560
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		157	167	186	209	252	301	356
Exports of electricity (GWh)								
Contracted for base load		227	0	0	0	0	0	0
Contracted for intermediate load		0	0	0	0	0	0	0
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.11. Portugal

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		31909	32829	38498	44978	52499	60759	70258
GDP Deflator (1985=100)		249.60	288.12	366.39	465.38	589.37	745.61	942.35
Interest rate (%)		22.35	16.72	16.80	16.44	16.10	15.54	15.54
Exchange rate (curr./$)		135.00	176.27	189.82	200.18	210.36	223.04	239.05
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2407	2407	2407	2407	2407	2407	2407
	Fixed cost ($90/kW)	45	45	45	45	45	45	45
	Variable cost (mills$'90/kWh)	0.13	0.13	0.13	0.13	0.13	0.13	0.13
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1344	1344	1344	1327	1310	1293	1277
	Fixed cost ($90/kW)	50	50	50	50	49	49	48
	Variable cost (mills$'90/kWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1407	1407	1407	1390	1372	1355	1337
	Fixed cost ($90/kW)	52	52	52	52	51	51	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1510	1510	1510	1510	1510	1510	1510
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1484	1484	1484	1451	1419	1386	1353
	Fixed cost ($90/kW)	55	55	55	54	53	51	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	915	915	915	903	892	880	869
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	48%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	387	387	387	387	387	387	387
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1891	1891	1891	1754	1626	1546	1508
	Fixed cost ($90/kW)	68	68	68	63	58	56	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		2537	4200	2400	2400	2400	2400	2400
Contracted for intermediate load		0	0	0	0	0	0	0
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		128	128	149	172	200	229	260
Exports of Electricity (GWh)								
Contracted for base load		1197	1250	1250	1250	1250	1250	1250
Contracted for intermediate load		0	0	0	0	0	0	0
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.12. Spain

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		355222	369097	424177	483838	552607	622820	703664
GDP deflator (1985=100)		162.80	183.41	230.76	287.89	355.98	436.74	535.94
Interest rate (%)		14.23	12.28	10.67	10.17	9.89	9.89	9.90
Exchange rate (curr./$)		102.38	138.99	147.52	149.31	149.86	151.01	153.77
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2398	2398	2398	2398	2398	2398	2398
	Fixed cost ($90/kW)	45	45	45	45	45	45	45
	Variable cost (mills$'90/kWh)	0.18	0.18	0.18	0.18	0.18	0.18	0.18
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1343	1343	1343	1326	1310	1293	1276
	Fixed cost ($90/kW)	50	50	50	50	49	49	48
	Variable cost (mills$'90/kWh)	1.14	1.14	1.14	1.14	1.14	1.14	1.14
	Efficiency rate (%)	39%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1407	1407	1407	1389	1372	1354	1337
	Fixed cost ($90/kW)	52	52	52	52	51	50	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1510	1510	1510	1510	1510	1510	1510
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1483	1483	1483	1451	1418	1385	1353
	Fixed cost ($90/kW)	55	55	55	54	53	51	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	917	917	917	905	894	882	871
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	450	450	450	450	450	450	450
	Fixed cost ($90/kW)	18	18	18	18	18	18	18
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	30%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1891	1891	1891	1753	1626	1546	1508
	Fixed cost ($90/kW)	68	68	68	63	58	56	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		4210	7000	11000	7000	3000	3000	3000
Contracted for intermediate load		140	100	100	100	100	100	100
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		61	62	69	75	86	98	111
Exports of electricity (GWh)								
Contracted for base load		3509	2900	2700	2900	3100	3100	3100
Contracted for intermediate load		201	400	600	400	200	200	200
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.13. Sweden

		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		156515	159126	178132	199522	223095	243228	264767
GDP deflator (1985=100)		164.66	175.63	200.62	232.19	270.82	317.73	372.85
Interest rate (%)		15.43	10.59	10.62	10.47	10.48	10.47	10.48
Exchange rate (curr./$)		5.82	7.72	7.29	6.90	6.50	6.13	5.84
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2406	2406	2406	2406	2406	2406	2406
	Fixed cost ($90/kW)	45	45	45	45	45	45	45
	Variable cost (mills$'90/kWh)	3.04	3.04	3.04	3.04	3.04	3.04	3.04
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1343	1343	1343	1326	1309	1293	1276
	Fixed cost ($90/kW)	50	50	50	50	49	49	48
	Variable cost (mills$'90/kWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02
	Efficiency rate (%)	40%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1407	1407	1407	1389	1371	1354	1336
	Fixed cost ($90/kW)	52	52	52	52	51	50	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	39%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1509	1509	1509	1509	1509	1509	1509
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	35%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1483	1483	1483	1450	1418	1385	1352
	Fixed cost ($90/kW)	55	55	55	54	53	51	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	39%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	916	916	916	905	894	882	871
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	387	387	387	387	387	387	387
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1895	1895	1895	1757	1629	1550	1511
	Fixed cost ($90/kW)	68	68	68	63	59	56	54
	Variable cost (mills$'90/kWh)	2.11	2.11	2.11	2.11	2.11	2.11	2.11
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		6634	6000	6000	6000	6003	6007	6011
Contracted for intermediate load		2211	2000	2000	2000	2001	2002	2004
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		63	57	65	76	94	118	145
Exports of electricity (GWh)								
Contracted for base load		8246	6000	6000	6000	6000	6000	6000
Contracted for intermediate load		2749	2000	2000	2000	2000	2000	2000
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

Table A4.14. United Kingdom

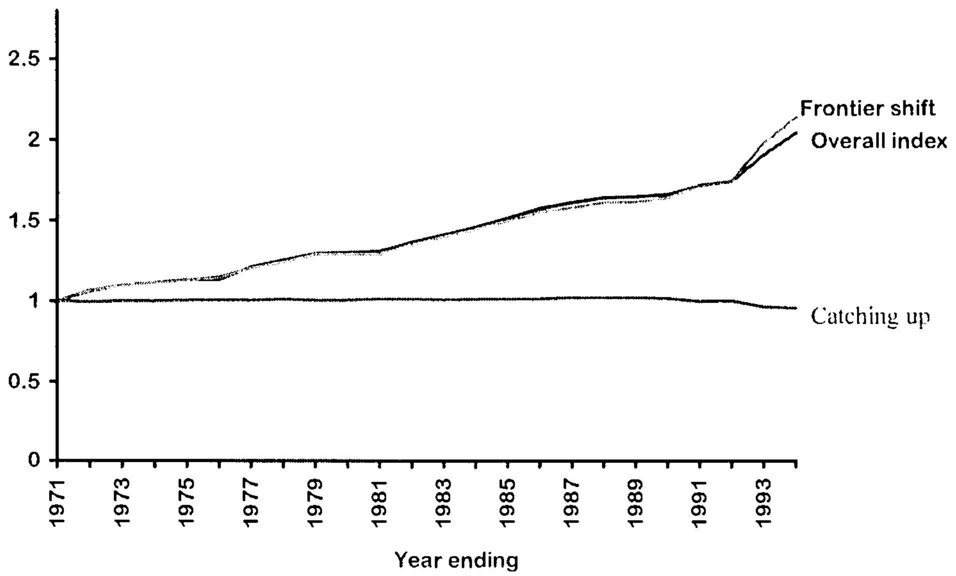
		1992	1995	2000	2005	2010	2015	2020
Macro-economic variables								
Gross Domestic Product ($90m)		720528	783464	890808	994660	1101743	1211430	1327092
GDP deflator (1985=100)		146.90	159.24	191.02	228.81	275.99	332.77	401.12
Interest rate (%)		9.41	7.77	8.04	7.77	7.78	7.78	7.78
Exchange rate (curr./$)		0.57	0.67	0.68	0.67	0.65	0.65	0.65
Discount rate (%, real)		9.00	8.00	8.00	8.00	8.00	8.00	8.00
Technicoeconomics of new power plants								
Nuclear	Investment cost ($90/kW)	2401	2401	2401	2401	2401	2401	2401
	Fixed cost ($90/kW)	45	45	45	45	45	45	45
	Variable cost (mills$'90/kWh)	32.03	32.03	32.03	32.03	32.03	32.03	32.03
	Efficiency rate (%)	33%	33%	33%	33%	33%	33%	33%
Fuel oil	Investment cost ($90/kW)	1340	1340	1340	1323	1307	1290	1273
	Fixed cost ($90/kW)	50	50	50	50	49	48	48
	Variable cost (mills$'90/kWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02
	Efficiency rate (%)	38%	38%	39%	39%	40%	41%	41%
Coal	Investment cost ($90/kW)	1404	1404	1404	1386	1369	1351	1334
	Fixed cost ($90/kW)	52	52	52	52	51	50	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Brown coal	Investment cost ($90/kW)	1512	1512	1512	1512	1512	1512	1512
	Fixed cost ($90/kW)	91	91	91	91	91	91	91
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	39%	39%	40%	40%
Polyvalent	Investment cost ($90/kW)	1480	1480	1480	1447	1415	1382	1350
	Fixed cost ($90/kW)	55	55	55	54	52	51	50
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	38%	38%	38%	38%	39%	39%	40%
Gas comb. cycle	Investment cost ($90/kW)	918	918	918	907	895	884	872
	Fixed cost ($90/kW)	27	27	27	26	26	26	25
	Variable cost (mills$'90/kWh)	1.78	1.78	1.78	1.78	1.78	1.78	1.78
	Efficiency rate (%)	52%	52%	54%	56%	58%	61%	63%
Peak devices	Investment cost ($90/kW)	386	386	386	386	386	386	386
	Fixed cost ($90/kW)	15	15	15	15	15	15	15
	Variable cost (mills$'90/kWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Efficiency rate (%)	32%	32%	33%	34%	35%	36%	37%
Advanced coal	Investment cost ($90/kW)	1894	1894	1894	1756	1628	1548	1510
	Fixed cost ($90/kW)	68	68	68	63	59	56	54
	Variable cost (mills$'90/kWh)	2.10	2.10	2.10	2.10	2.10	2.10	2.10
	Efficiency rate (%)	44%	44%	46%	48%	50%	52%	54%
Imports of electricity (GWh)								
Contracted for base load		16722	12000	12000	12000	12000	12000	12000
Contracted for intermediate load		0	0	0	0	0	0	0
Contracted for peak load		0	0	0	0	0	0	0
Peak reserve from imports (GW)		10	10	10	10	10	10	10
Price of imports ($m/kWh)		66	76	92	104	122	142	163
Exports of electricity (GWh)								
Contracted for base load		32	47	47	47	47	47	47
Contracted for intermediate load		0	0	0	0	0	0	0
Contracted for peak load		0	0	0	0	0	0	0
LOLP constraint (hours)		4.38	4.38	4.38	4.38	4.38	4.38	4.38

A5. UK liberalization

A5.1. Productivity in UK electricity distribution

Figure A5.1 reports productivity growth in the industry since 1971. It shows that for most of the period productivity growth has averaged about 2.5% per year and that less efficient firms have neither caught up with the frontier nor moved further away from it. However, by 1993 the frontier started to move out quite sharply, by 13% in 1992/93 and 8% in 1993/94. The less efficient firms could not keep up with this frontier shift and the catching-up index (a measure of the extent to which firms on average catch up with best practice) fell significantly. This analysis implies that if prices and costs are transparent and there are appropriate incentives on management (in this case, a desire to create rewards for shareholders), then significant efficiency gains can be made. Furthermore, the scope for incremental efficiency improvement is large. The analysis here shows a gain of more than 10% above trend in just two years.

Figure A5.1. Productivity growth in electricity distribution in England and Wales, 1971–94



A5.2. Estimates of future changes in UK residential electricity prices

Figure A5.2 shows an estimate of the likely change in the bill for a typical residential consumer in the UK between now and 2000. In line with the price data shown elsewhere in this Appendix, the price of electricity to residential consumers is shown to have fallen only slightly in real terms between 1990 and 1995. However, as the favourable terms given to the companies at privatization are removed, price falls are expected to be much larger. The projected fall includes a reduction in distribution prices of over 30% imposed by the regulator and continuing falls in the price of bulk electricity.

Figure A5.2. Estimate of projected electricity prices for UK residential consumers, 1992–2001

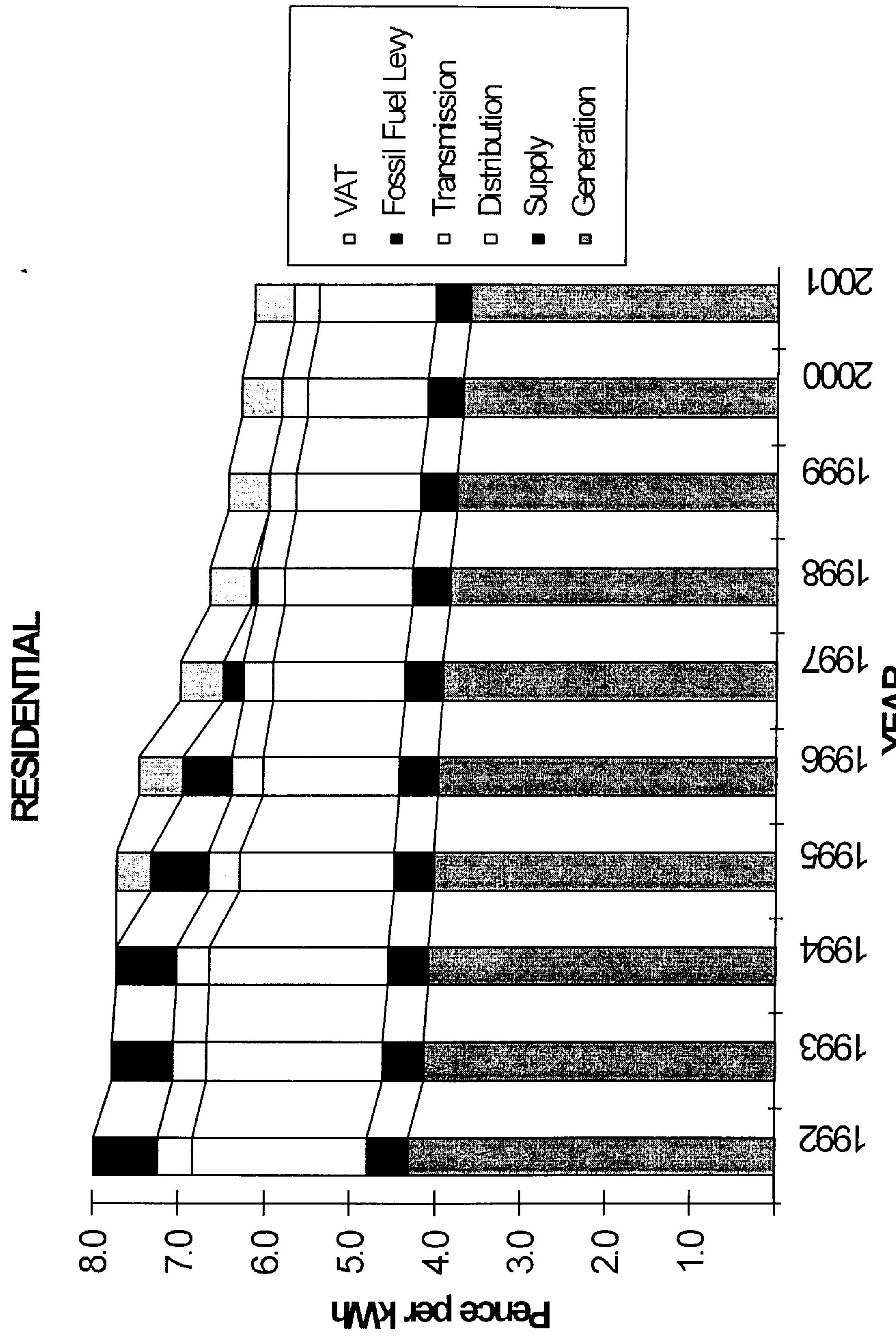
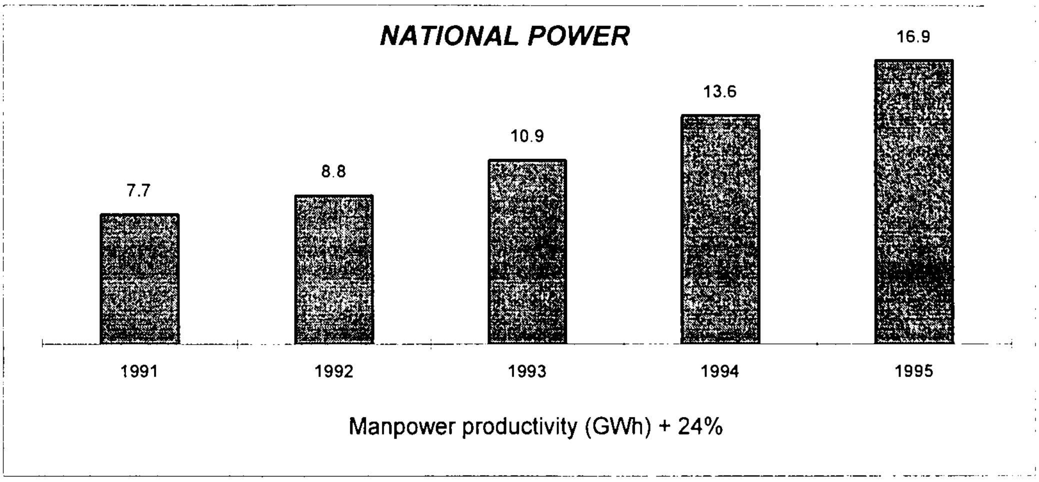
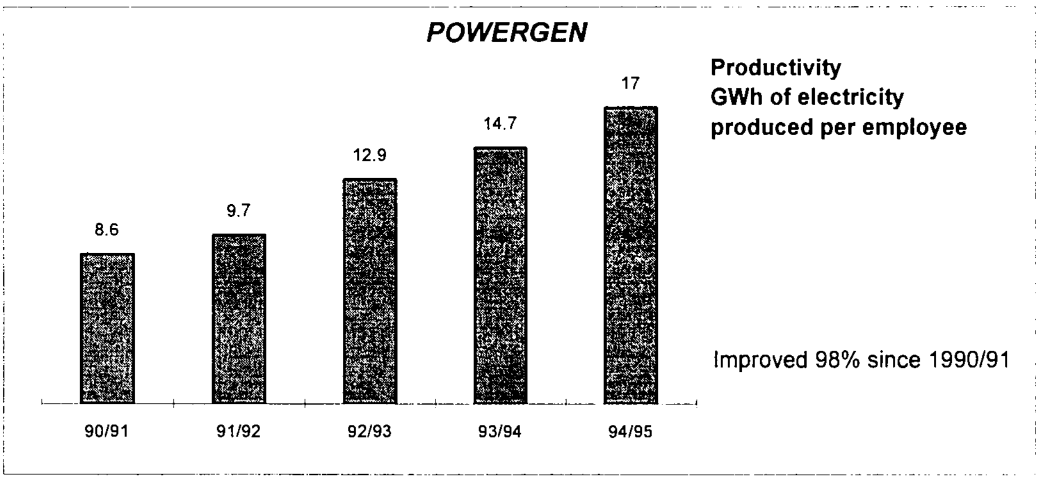
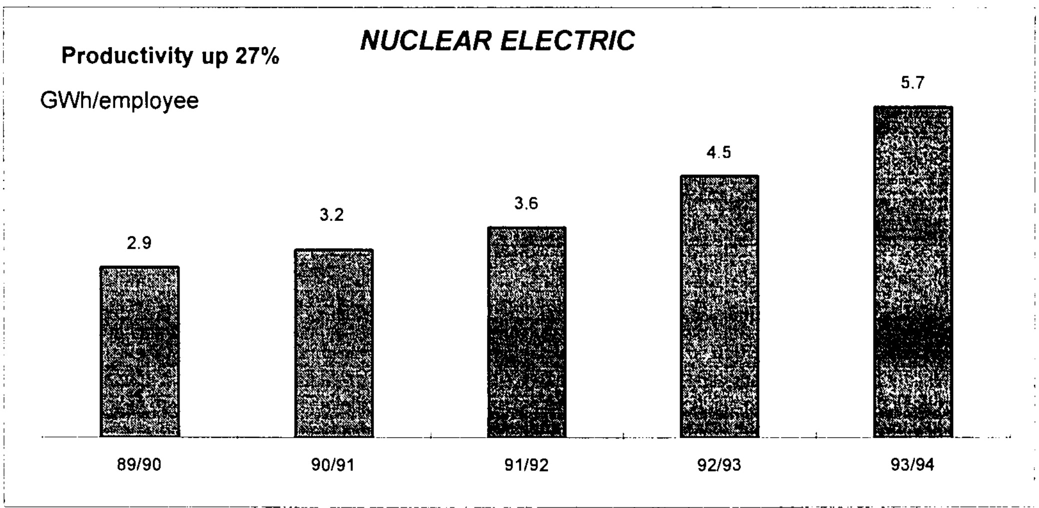


Figure A5.3. Productivity growth for National Power, PowerGen and Nuclear Electric







A6. Base case

Table A6.1. Base case power generation forecasts for Europe

EWI-NH : BASE CASE CAPACITIES
Power Generation by fuel in TWh
Germany

	1993 (act.)	2000	2005	2010	2015	2020
HC	99	149	129	143	151	188
BC	117	134	138	140	128	87
OIL	3	0	0	0	0	0
GAS	15	83	136	152	183	213
NUC	144	145	145	145	145	145
HYDRO	19	20	21	21	22	23
Sum	397	531	569	602	629	656

Power Generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Germany

	1993 (act.)	2000	2005	2010	2015	2020
HC	25	28	23	24	24	29
BC	30	25	24	23	20	13
OIL	1	0	0	0	0	0
GAS	4	16	24	25	29	32
NUC	36	27	25	24	23	22
HYDRO	5	4	4	4	4	4
Sum	100	100	100	100	100	100

Power Generation by fuel in TWh
France

	1993 (act.)	2000	2005	2010	2015	2020
HC	20	18	13	9	20	24
OIL	4	0	0	0	0	0
GAS	7	3	3	3	2	11
NUC	350	327	348	385	399	413
HYDRO	72	89	96	94	92	91
Sum	453	436	460	491	514	538

Power Generation by fuel in per cent (sum of figures may not total 100 due to rounding)
France

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	4	3	2	4	4
OIL	1	0	0	0	0	0
GAS	2	1	1	1	0	2
NUC	77	75	76	78	78	77
HYDRO	16	20	21	19	18	17
Sum	100	100	100	100	100	100

Power Generation by fuel in TWh
Benelux

	1993 (act.)	2000	2005	2010	2015	2020
HC	37	68	59	59	49	24
OIL	1	0	0	0	0	0
GAS	57	37	56	64	81	109
NUC	43	44	44	44	43	43
HYDRO	2	2	2	2	2	2
Sum	140	150	160	169	175	179

Table A6.1. Base case power generation forecasts for Europe (continued)

EWI-NH : BASE CASE CAPACITIES

Power Generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Benelux

	1993 (act.)	2000	2005	2010	2015	2020
HC	27	45	37	35	28	13
OIL	1	0	0	0	0	0
GAS	40	25	35	38	46	61
NUC	31	29	27	26	25	24
HYDRO	1	1	1	1	1	1
Sum	100	100	100	100	100	100

Power Generation by fuel in TWh
Austria / Switzerland

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	11	7	3	2	2
BC	1	1	1	1	1	0
OIL	2	0	0	0	0	0
GAS	7	1	1	5	3	4
NUC	22	22	22	22	22	22
HYDRO	74	71	72	77	81	86
Sum	110	106	103	107	109	113

Power Generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Austria / Switzerland

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	11	7	2	2	2
BC	1	1	1	1	1	0
OIL	2	0	0	0	0	0
GAS	6	1	1	4	3	4
NUC	20	20	21	20	20	19
HYDRO	67	67	70	72	75	76
Sum	100	100	100	100	100	100

Power Generation by fuel in TWh
Portugal / Spain

	1993 (act.)	2000	2005	2010	2015	2020
HC	56	63	70	71	74	42
BC	12	13	13	13	1	1
OIL	10	3	4	0	0	0
GAS	0	0	9	31	58	106
NUC	53	56	56	56	56	56
HYDRO	31	42	42	43	45	46
Sum	162	177	193	214	234	250

Power Generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Portugal / Spain

	1993 (act.)	2000	2005	2010	2015	2020
HC	35	35	36	33	32	17
BC	7	8	7	6	0	0
OIL	6	2	2	0	0	0
GAS	0	0	4	14	25	42
NUC	33	32	29	26	24	22
HYDRO	19	24	22	20	19	18
Sum	100	100	100	100	100	100

Table A6.2. Base case power capacity forecasts for Europe

EWI-NH : BASE CASE CAPACITIES

German capacity development [MW]

	1993 (act.)	2000	2005	2010	2015	2020
HC	23328	22455	20351	19747	20733	25274
BC	20139	20858	22538	22538	17182	11681
OIL	5435	2174	1441	544	310	285
GAS	10448	16665	22925	29667	39643	47499
NUC	22507	20866	20866	20866	20866	20866
HYDRO	8250	8607	8817	9171	9524	9878
Sum	90106	91624	96938	102532	108257	115483

French capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	11840	9973	8081	5113	5113	4003
OIL	6262	3323	2796	841	685	685
GAS	1699	3785	4697	12990	13369	13538
NUC	57675	64795	64795	64795	64022	66157
HYDRO	24996	24636	24636	25343	26050	26757
Sum	102472	106512	105005	109082	109239	111140

Austria/Switzerland capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	1517	2226	2226	1420	994	994
BC	460	742	742	742	605	275
OIL	3649	692	692	650	619	574
GAS	570	2492	2967	5617	6431	7376
NUC	2950	2868	2868	2868	2868	2868
HYDRO	22826	24116	24629	26004	27378	28753
Sum	31972	33136	34124	37301	38895	40840

Benelux capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	7536	9826	8467	8275	7408	6161
OIL	1112	574	574	574	574	414
GAS	11587	10810	13486	16352	21204	23130
NUC	5990	5785	5785	5785	5785	5785
HYDRO	2562	2393	2393	2393	2393	2393
Sum	28787	29388	30705	33379	37364	37883

Portugal/Spain capacity development [MW]

	1994 (act.)	2000	2005	2010	2015	2020
HC	9152	10414	10860	10380	10321	5783
BC	3400	1867	1867	1830	134	134
OIL	7886	6858	5083	1680	100	0
GAS	3902	2775	4376	10522	16828	23831
NUC	7400	7400	7400	7400	7400	7400
HYDRO	20324	20937	20937	21832	22729	23624
Sum	52064	50251	50523	53644	57512	60772

Table A6.3. Base case forecasts for European net imports

EWI-NH : BASE CASE CAPACITIES

Net-power imports 1993 (Net Imports+, Net Exports-); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	13.362	-3.554	-13.841	0	2.88	0.826	0	0
F	-13.362	0	-8.912	-2.768	-1.570	0	0	-16.759	-17.279
A / CH	3.554	8.912	0	0	0	0	2.495	0	-21.201
Benelux	13.841	2.768	0	0	0	0	0	0	0
IB	0	1.570	0	0	0				
Scand.	-2.88	0	0	0	0				
Ost-E.	-0.826	0	-2.495	0	0				
UK	0	16.759	0	0	0				
I	0	17.279	21.201	0	0				

Net-power imports 1995 (Net Imports+, Net Exports-); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	13.368	-1.372	-3.697	0	6.5	0.451	0	0
F	-13.368	0	-9.141	-3.799	-2.354	0	0	-14.736	-13.124
A / CH	1.372	9.141	0	0	0	0	2.3	0	-15.137
Benelux	3.697	3.799	0	0	0	0	0	0	0
IB	0	2.354	0	0	0				
Scand.	-6.5	0	0	0	0				
Ost-E.	-0.451	0	-2.3	0	0				
UK	0	14.736	0	0	0				
I	0	13.124	15.137	0	0				

Net-power imports 2000 (Net Imports+, Net Exports-); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	15.369	-3.762	-4.185	0	3.487	1.152	0	0
F	-15.369	0	-10.267	-4.124	-2.541	0	0	-14.463	-10.252
A / CH	3.762	10.267	0	0	0	0	3.18	0	-11.515
Benelux	4.185	4.124	0	0	0	-1.793	0	0	0
IB	0	2.541	0	0	0				
Scand.	-3.487	0	0	1.793	0				
Ost-E.	-1.152	0	-3.18	0	0				
UK	0	14.463	0	0	0				
I	0	10.252	11.515	0	0				

Net-power imports 2005 (Net Imports+, Net Exports-); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	16.533	-3.972	-4.49	0	4.513	2.848	0	0
F	-16.533	0	-10.988	-4.389	-2.175	0	0	-13.863	-3.112
A / CH	3.972	10.988	0	0	0	0	4.208	0	-3.008
Benelux	4.49	4.389	0	0	0	-1.724	0	0	0
IB	0	2.175	0	0	0				
Scand.	-4.513	0	0	1.724	0				
Ost-E.	-2.848	0	-4.208	0	0				
UK	0	13.863	0	0	0				
I	0	3.112	3.008	0	0				

Table A6.3. Base case forecasts for European net imports (continued)

EWI-NH : BASE CASE CAPACITIES

Net-power imports 2010 (Net Imports+, Net Exports-); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	17.525	-3.221	-4.755	0	3.833	4.387	0	0
F	-17.525	0	-11.447	-4.631	-3.094	0	0	-13.863	-1.532
A / CH	3.221	11.447	0	0	0	0	4.07	0	-0.980
Benelux	4.755	4.631	0	0	0	-1.643	0	0	0
IB	0	3.094	0	0	0				
Scand.	-3.833	0	0	1.643	0				
Ost-E.	-4.387	0	-4.07	0	0				
UK	0	13.863	0	0	0				
I	0	1.532	0.980	0	0				

Net-power imports 2015 (Net Imports+, Net Exports-); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	18.236	-4.897	-4.937	0	3.879	3.446	0	0
F	-18.236	0	-11.866	-3.409	-2.511	0	0	-13.582	-1.124
A / CH	4.897	11.866	0	0	0	0	4.871	0	-1.388
Benelux	4.937	3.409	0	0	0	-1.549	0	0	0
IB	0	2.511	0	0	0				
Scand.	-3.879	0	0	1.549	0				
Ost-E.	-3.446	0	-4.871	0	0				
UK	0	13.582	0	0	0				
I	0	1.124	1.388	0	0				

Net-power imports 2020 (Net Imports+, Net Exports-); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	13.841	-4.023	-5.088	0	3.922	3.765	0	0
F	-13.841	0	-11.838	-2.692	-2.530	0	0	-13.582	-0.717
A / CH	4.023	11.838	0	0	0	0	4.64	0	-1.795
Benelux	5.088	2.692	0	0	0	-1.444	0	0	0
IB	0	2.530	0	0	0				
Scand.	-3.922	0	0	1.444	0				
Ost-E.	-3.765	0	-4.64	0	0				
UK	0	13.582	0	0	0				
I	0	0.717	1.795	0	0				

Table A6.4. EWI-NH: Base case capacities

Transmission capacity additions

Germany

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	1200	0	1326.17	0	0	0
O	0	294.11	24.69	28.81	37.04	6.17
UK	0	0	0	0	0	0
IT	0	0	0	0	0	0

France

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	0	0	0	0	0
O	0	0	0	0	0	0
UK	42.01	0	7.17	0	118.33	0
IT	0	0	0	0	0	0

Austria and Switzerland

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	0	0	0	0	0
O	600	0	667.43	0	0	0
UK	0	0	0	0	0	0
IT	378.66	0	145.23	0	0	0

Benelux

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	855.61	0	0	0	0
O	0	0	0	0	0	0
UK	0	0	0	0	0	0
IT	0	0	0	0	0	0

Iberia

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	0	0	0	0	0
O	0	0	0	0	0	0
UK	0	0	0	0	0	0
IT	0	0	0	0	0	0

Table A6.5. EWI-NH: Base case data

EWI-NH : Base case data

Germany

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0	0
F	6375	6375	6375	6375	6375	6375	6375
A	18935	18935	18935	18935	18935	18935	18935
L	10104	10104	10104	10104	10104	10104	10104
IB	0	0	0	0	0	0	0
N	2235	3435	3435	4761	4761	4761	4761
O	5100	5100	5394	5419	5448	5485	5491
UK	0	0	0	0	0	0	0
IT	0	0	0	0	0	0	0

France

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	6375	6375	6375	6375	6375	6375	6375
F	0	0	0	0	0	0	0
A	5335	5335	5335	5335	5335	5335	5335
L	3335	3335	3335	3335	3335	3335	3335
IB	3429	3429	3429	3429	3429	3429	3429
N	0	0	0	0	0	0	0
O	0	0	0	0	0	0	0
UK	2000	2042	2042	2049	2049	2168	2168
IT	4290	4290	4290	4290	4290	4290	4290

Austria and Switzerland

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	18935	18935	18935	18935	18935	18935	18935
F	5335	5335	5335	5335	5335	5335	5335
A	0	0	0	0	0	0	0
L	0	0	0	0	0	0	0
IB	0	0	0	0	0	0	0
N	0	0	0	0	0	0	0
O	2104	2704	2704	3371	3371	3371	3371
UK	0	0	0	0	0	0	0
IT	3982	4361	4361	4506	4506	4506	4506

Benelux

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	10104	10104	10104	10104	10104	10104	10104
F	3335	3335	3335	3335	3335	3335	3335
A	0	0	0	0	0	0	0
L	0	0	0	0	0	0	0
IB	0	0	0	0	0	0	0
N	0	0	856	856	856	856	856
O	0	0	0	0	0	0	0
UK	0	0	0	0	0	0	0
IT	0	0	0	0	0	0	0

Iberia

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0	0
F	3429	3429	3429	3429	3429	3429	3429
A	0	0	0	0	0	0	0
L	0	0	0	0	0	0	0
IB	0	0	0	0	0	0	0
N	0	0	0	0	0	0	0
O	0	0	0	0	0	0	0
UK	0	0	0	0	0	0	0
IT	0	0	0	0	0	0	0

Table A6.6. Capacity utilization of generation plant per hour by year

EWI-NH : BASE CASE CAPACITIES
Base case

Germany

	1995	2000	2005	2010	2015	2020
HC	6273	6656	6310	7173	7159	7148
HCGUD	0	0	0	7617	7617	7617
HCGAS	0	0	7442	7442	7442	6762
BC	6304	6429	6122	6233	7426	7437
OIL	0	0	0	0	0	0
GASGUD	0	7530	7530	6040	5226	4992
GASTUR	351	339	254	226	211	0
NUC	6950	6950	6949	6946	6937	6933

France

	1995	2000	2005	2010	2015	2020
HC	1863	1830	1680	1818	3995	6015
HCGUD	0	0	0	0	0	0
HCGAS	0	0	0	0	0	0
OIL	0	0	0	0	0	0
GASGUD	0	2288	1802	268	237	1058
GASTUR	4975	5041	5366	5944	6235	6245

Austria/Switzerland

	1995	2000	2005	2010	2015	2020
HC	1965	5085	3242	1771	1775	1503
HCGUD	0	0	0	0	0	0
HCGAS	0	0	0	0	0	0
BC	5060	1892	1485	0	0	0
OIL	0	0	0	0	0	0
GASGUD	0	0	0	1744	991	1099
GASTUR	7530	7530	7524	7518	7513	7513

Benelux

	1995	2000	2005	2010	2015	2020
HC	6849	6877	6909	7174	6583	3995
HCGUD	0	0	0	0	0	0
HCGAS	7442	7442	7442	7442	7442	0
OIL	0	0	0	0	0	0
GASGUD	7880	7672	6870	5805	5289	6580
GASTUR	7530	7530	7530	7522	7519	7515

Iberia

	1995	2000	2005	2010	2015	2020
HC	5042	6007	6408	6824	7158	7157
HCGUD	0	0	0	7617	7617	7617
HCGAS	0	0	0	0	0	0
BC	6749	7201	6795	7113	0	0
OIL	0	396	876	0	0	0
GASGUD	0	0	5334	4459	4541	5473
GASTUR	7530	7530	7529	7527	7530	7504

Table A6.7. Base case share of new technologies

EWI-NH : BASE CASE CAPACITIES
New. Tech: GTCC & IGCC

German capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	6497	13216	19542	29011	41682	59741
Conv.Tech.	80971	78409	77396	73521	66575	55742
Sum	87468	91624	96938	102532	108257	115483

German capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	7.43	14.42	20.16	28.29	38.50	51.73
Conv.Tech.	92.57	85.58	79.84	71.71	61.50	48.27
Sum	100	100	100	100	100	100

French capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	657	2000	1820	9959	10176	10176
Conv.Tech.	105844	104512	103185	99123	99063	100964
Sum	106501	106512	105005	109082	109239	111140

French capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	0.62	1.88	1.73	9.13	9.32	9.16
Conv.Tech.	99.38	98.12	98.27	90.87	90.68	90.84
Sum	100	100	100	100	100	100

Austrian/Swiss capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	0	152	152	2520	3082	3687
Conv.Tech.	32404	32984	33972	34781	35813	37153
Sum	32404	33136	34124	37301	38895	40840

Austrian/Swiss capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	0.00	0.46	0.45	6.76	7.92	9.03
Conv.Tech.	100.00	99.54	99.55	93.24	92.08	90.97
Sum	100	100	100	100	100	100

Benelux capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	9327	7512	8708	11072	15371	16688
Conv.Tech.	20608	21876	21997	22307	21993	21195
Sum	29935	29388	30705	33379	37364	37883

Table A6.7. Base case share of new technologies (continued)

EWI-NH : BASE CASE CAPACITIES

Benelux capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	31.16	25.56	28.36	33.17	41.14	44.05
Conv.Tech.	68.84	74.44	71.64	66.83	58.86	55.95
Sum	100	100	100	100	100	100

Iberian capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	0	0	1579	7137	13077	19677
Conv.Tech.	50975	50251	48943	46507	44435	41095
Sum	50975	50251	50523	53644	57512	60772

Iberian capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	0.00	0.00	3.13	13.30	22.74	32.38
Conv.Tech.	100.00	100.00	96.87	86.70	77.26	67.62
Sum	100	100	100	100	100	100

Table A6.8. Base case grid utilization

EWI-NH : BASE CASE CAPACITIES
Grid-utilization: Actual flows [TWh]/Maximum flow capacity [TWh]
CAPR-nh = BaseCase

1994 (act.)

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.13	0.38	0.00	0.20	0.02	0.00	0.00
F	0.54	0.00	0.33	0.32	0.25	0.00	0.00	0.00	0.01
A	0.13	0.03	0.00	0.00	0.00	0.00	0.34	0.00	0.00
L	0.03	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IB	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.20	0.00	0.00	0.00	0.00				
O	0.02	0.00	0.34	0.00	0.00				
UK	0.00	0.00	0.00	0.00	0.00				
IT	0.00	0.01	0.00	0.00	0.00				

1995

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.12	0.10	0.00	0.29	0.04	0.00	0.00
F	0.48	0.00	0.40	0.29	0.18	0.00	0.00	0.03	0.00
A	0.11	0.00	0.00	0.00	0.00	0.00	0.28	0.00	0.03
L	0.01	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IB	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.29	0.00	0.00	0.00	0.00				
O	0.04	0.00	0.28	0.00	0.00				
UK	0.00	0.03	0.00	0.00	0.00				
IT	0.00	0.00	0.03	0.00	0.00				

2000

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.17	0.11	0.00	0.29	0.07	0.00	0.00
F	0.55	0.00	0.44	0.31	0.19	0.00	0.00	0.05	0.00
A	0.12	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.04
L	0.02	0.03	0.00	0.00	0.00	0.29	0.00	0.00	0.00
IB	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.29	0.00	0.00	0.29	0.00				
O	0.07	0.00	0.36	0.00	0.00				
UK	0.00	0.05	0.00	0.00	0.00				
IT	0.00	0.00	0.04	0.00	0.00				

2005

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.18	0.12	0.00	0.29	0.15	0.00	0.00
F	0.59	0.00	0.48	0.34	0.21	0.00	0.00	0.08	0.00
A	0.13	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.04
L	0.02	0.03	0.00	0.00	0.00	0.30	0.00	0.00	0.00
IB	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.29	0.00	0.00	0.30	0.00				
O	0.15	0.00	0.36	0.00	0.00				
UK	0.00	0.08	0.00	0.00	0.00				
IT	0.00	0.00	0.04	0.00	0.00				

2010

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.18	0.13	0.00	0.32	0.22	0.00	0.00
F	0.63	0.00	0.50	0.35	0.23	0.00	0.00	0.08	0.00
A	0.14	0.01	0.00	0.00	0.00	0.00	0.36	0.00	0.05
L	0.02	0.04	0.00	0.00	0.00	0.31	0.00	0.00	0.00
IB	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.32	0.00	0.00	0.31	0.00				
O	0.22	0.00	0.36	0.00	0.00				
UK	0.00	0.08	0.00	0.00	0.00				
IT	0.00	0.00	0.05	0.00	0.00				

2015

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.19	0.13	0.00	0.32	0.18	0.00	0.00
F	0.65	0.00	0.51	0.37	0.25	0.00	0.00	0.09	0.03
A	0.13	0.01	0.00	0.00	0.00	0.00	0.42	0.00	0.03
L	0.02	0.13	0.00	0.00	0.00	0.32	0.00	0.00	0.00
IB	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.32	0.00	0.00	0.32	0.00				
O	0.18	0.00	0.42	0.00	0.00				
UK	0.00	0.09	0.00	0.00	0.00				
IT	0.00	0.03	0.03	0.00	0.00				

Table A6.8. Base case grid utilization (continued)

EWI-NH : BASE CASE CAPACITIES

2020

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.20	0.14	0.00	0.32	0.20	0.00	0.00
F	0.50	0.00	0.53	0.33	0.27	0.00	0.00	0.09	0.05
A	0.15	0.02	0.00	0.00	0.00	0.00	0.41	0.00	0.01
L	0.02	0.14	0.00	0.00	0.00	0.33	0.00	0.00	0.00
IB	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.32	0.00	0.00	0.33	0.00				
O	0.20	0.00	0.41	0.00	0.00				
UK	0.00	0.09	0.00	0.00	0.00				
IT	0.00	0.05	0.01	0.00	0.00				

A7. nTPA

Table A7.1. nTPA power generation forecasts for Europe

Power generation by fuel in TWh
Germany

	1993 (act.)	2000	2005	2010	2015	2020
HC	99	147	136	154	158	215
BC	117	134	138	141	128	87
OIL	3	0	0	0	0	0
GAS	15	45	95	112	151	175
NUC	144	145	145	145	145	145
HYDRO	19	20	21	21	22	23
Sum	397	491	534	573	604	644

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Germany

	1993 (act.)	2000	2005	2010	2015	2020
HC	25	30	25	27	26	33
BC	30	27	26	25	21	13
OIL	1	0	0	0	0	0
GAS	4	9	18	20	25	27
NUC	36	30	27	25	24	22
HYDRO	5	4	4	4	4	4
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
France

	1993 (act.)	2000	2005	2010	2015	2020
HC	20	18	13	19	30	26
OIL	4	0	0	0	0	0
GAS	7	3	3	3	6	15
NUC	350	369	386	405	402	416
HYDRO	72	95	96	94	93	91
Sum	453	485	499	521	532	548

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
France

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	4	3	4	6	5
OIL	1	0	0	0	0	0
GAS	2	1	1	1	1	3
NUC	77	76	77	78	76	76
HYDRO	16	20	19	18	17	17
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
Benelux

	1993 (act.)	2000	2005	2010	2015	2020
HC	37	70	60	59	53	44
OIL	1	0	0	0	0	0
GAS	57	36	49	59	80	87
NUC	43	44	44	44	43	43
HYDRO	2	2	2	2	2	2
Sum	140	152	155	165	178	177

Table A7.1. NTPA power generation forecasts for Europe (continued)

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Benelux

	1993 (act.)	2000	2005	2010	2015	2020
HC	27	46	39	36	30	25
OIL	1	0	0	0	0	0
GAS	40	24	32	36	45	49
NUC	31	29	28	26	24	25
HYDRO	1	1	1	1	1	1
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
Austria/Switzerland

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	6	7	8	6	6
BC	1	1	1	2	1	0
OIL	2	0	0	0	0	0
GAS	7	1	7	5	5	3
NUC	22	22	22	22	22	22
HYDRO	74	71	72	77	82	87
Sum	110	101	109	113	115	117

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Austria/Switzerland

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	6	7	7	5	5
BC	1	1	1	1	1	0
OIL	2	0	0	0	0	0
GAS	6	1	6	4	5	2
NUC	20	21	20	19	19	18
HYDRO	67	70	66	68	71	74
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
Portugal/Spain

	1993 (act.)	2000	2005	2010	2015	2020
HC	56	60	68	69	73	40
BC	12	13	13	13	1	1
OIL	10	2	4	0	0	0
GAS	0	0	6	31	59	108
NUC	53	56	56	56	56	56
HYDRO	31	42	42	43	45	46
Sum	162	173	189	211	233	250

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Portugal/Spain

	1993 (act.)	2000	2005	2010	2015	2020
HC	35	35	36	32	31	16
BC	7	8	7	6	0	0
OIL	6	1	2	0	0	0
GAS	0	0	3	15	25	43
NUC	33	32	29	26	24	22
HYDRO	19	24	22	20	19	18
Sum	100	100	100	100	100	100

Table A7.2. nTPA power capacity forecasts for Europe

German capacity development [MW]

	1993 (act.)	2000	2005	2010	2015	2020
HC	23328	21668	20351	21435	21746	28799
BC	20139	20858	22538	22538	17182	11681
OIL	5435	2174	1441	544	310	285
GAS	10448	12544	18804	25546	35522	44025
NUC	22507	20866	20866	20866	20866	20866
HYDRO	8250	8607	8817	9171	9524	9878
Sum	90106	86717	92817	100100	105150	115534

French capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	11840	9973	8081	5113	5113	4003
OIL	6262	3323	2796	841	685	685
GAS	1699	3785	5859	14134	14296	14465
NUC	57675	64795	64795	64795	64022	66157
HYDRO	24996	24636	24636	25343	26050	26757
Sum	102472	106512	106167	110226	110166	112067

Austrian/Swiss capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	1517	2226	2226	1420	994	994
BC	460	742	742	742	605	275
OIL	3649	692	692	650	619	574
GAS	570	2492	4927	5617	6228	6568
NUC	2950	2868	2868	2868	2868	2868
HYDRO	22826	24116	24629	26004	27378	28753
Sum	31972	33136	36084	37301	38692	40032

Benelux capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	7536	10255	8467	8275	7408	6161
OIL	1112	574	574	574	574	414
GAS	11587	11357	14321	18070	24038	24205
NUC	5990	5785	5785	5785	5785	5785
HYDRO	2562	2393	2393	2393	2393	2393
Sum	28787	30364	31540	35097	40198	38958

Iberian capacity development [MW]

	1994 (act.)	2000	2005	2010	2015	2020
HC	9152	9955	10860	10216	10157	5619
BC	1800	1836	1836	1830	134	134
OIL	7886	6858	5083	1680	100	0
GAS	3902	2775	4663	10276	16582	22730
NUC	7400	7400	7400	7400	7400	7400
HYDRO	20324	20937	20937	21832	22729	23624
Sum	52064	49761	50778	53234	57102	59507

Table A7.3. nTPA forecasts for European net imports

Net-power imports 1993 (net imports + net exports); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	13.362	-3.554	-13.841	0	2.88	0.826	0	0
F	-13.362	0	-8.912	-2.768	-1.570	0	0	-16.759	-17.279
A / CH	3.554	8.912	0	0	0	0	2.495	0	-21.201
Benelux	13.841	2.768	0	0	0	0	0	0	0
IB	0	1.570	0	0	0				
Scand.	-2.88	0	0	0	0				
Ost-E.	-0.826	0	-2.495	0	0				
UK	0	16.759	0	0	0				
I	0	17.279	21.201	0	0				

Net-power imports 1995 (net imports + net exports); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	29.164	6.676	-2.555	0	6.5	0.451	0	0
F	-29.164	0	-17.883	-13.066	-10.272	0	0	-14.736	-13.124
A / CH	-6.676	17.883	0	0	0	0	2.3	0	-15.137
Benelux	2.555	13.066	0	0	0	0	0	0	0
IB	0	10.272	0	0	0				
Scand.	-6.5	0	0	0	0				
Ost-E.	-0.451	0	-2.3	0	0				
UK	0	14.736	0	0	0				
I	0	13.124	15.137	0	0				

Net-power imports 2000 (net imports + net exports); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	32.071	5.786	10.035	0	3.487	0.69	0	0
F	-32.071	0	-24.489	-17.220	-6.185	0	0	-14.048	-10.252
A / CH	-5.786	24.489	0	0	0	0	3.642	0	-11.515
Benelux	-10.035	17.220	0	0	0	-1.793	0	0	0
IB	0	6.185	0	0	0				
Scand.	-3.487	0	0	1.793	0				
Ost-E.	-0.69	0	-3.642	0	0				
UK	0	14.048	0	0	0				
I	0	10.252	11.515	0	0				

Net-power imports 2005 (net imports + net exports); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	31.218	11.134	0.487	0	4.513	3.299	0	0
F	-31.218	0	-20.751	-13.989	-5.982	0	0	-13.863	-3.078
A / CH	-11.134	20.751	0	0	0	0	3.757	0	-3.042
Benelux	-0.487	13.989	0	0	0	-1.724	0	0	0
IB	0	5.982	0	0	0				
Scand.	-4.513	0	0	1.724	0				
Ost-E.	-3.299	0	-3.757	0	0				
UK	0	13.863	0	0	0				
I	0	3.078	3.042	0	0				

Table A7.3. nTPA forecasts for European net imports (continued)

Net-power imports 2010 (net imports + net exports); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	30.904	9.247	-1.571	0	3.833	4.024	0	0
F	-30.904	0	-17.006	-12.175	-5.908	0	0	-13.682	-1.498
A / CH	-9.247	17.006	0	0	0	0	4.433	0	-1.014
Benelux	1.571	12.175	0	0	0	-1.643	0	0	0
IB	0	5.908	0	0	0				
Scand.	-3.833	0	0	1.643	0				
Ost-E.	-4.024	0	-4.433	0	0				
UK	0	13.682	0	0	0				
I	0	1.498	1.014	0	0				

Net-power imports 2015 (net imports + net exports); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	27.174	4.644	0.813	0	3.879	4.406	0	0
F	-27.174	0	-16.751	-6.540	-3.282	0	0	-13.582	-0.718
A / CH	-4.644	16.751	0	0	0	0	3.911	0	-1.794
Benelux	-0.813	6.540	0	0	0	-1.549	0	0	0
IB	0	3.282	0	0	0				
Scand.	-3.879	0	0	1.549	0				
Ost-E.	-4.406	0	-3.911	0	0				
UK	0	13.582	0	0	0				
I	0	0.718	1.794	0	0				

Net-power imports 2020 (net imports + net exports); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	20.146	-0.857	-2.749	0	3.858	3.409	0	0
F	-20.146	0	-11.214	-6.615	-2.587	0	0	-13.582	-0.718
A / CH	0.857	11.214	0	0	0	0	4.996	0	-1.794
Benelux	2.749	6.615	0	0	0	-1.38	0	0	0
IB	0	2.587	0	0	0				
Scand.	-3.858	0	0	1.38	0				
Ost-E.	-3.409	0	-4.996	0	0				
UK	0	13.582	0	0	0				
I	0	0.718	1.794	0	0				

Table A7.4. EWI-01: increased competition DATA NEG-TPA

Transmission capacity additions

Germany

	1995	2000	2005	2010	2015	2020
G	0.00	0	0	0	0	0
F	807	2593	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	1200	0	1326	0	0	0
O	0	294	25	29	37	6
UK	0	0	0	0	0	0
IT	0	0	0	0	0	0

France

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	281.19	1718.81	0	0	0	0
L	1387.56	612.44	0	0	0	0
IB	0	0	0	0	0	0
N	0	0	0	0	0	0
O	0	0	0	0	0	0
UK	42.01	0	7.17	73.67	44.66	0
IT	0	0	0	0	0	0

Austria and Switzerland

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	0	0	0	0	0
O	600	0	667.43	0	0	0
UK	0	0	0	0	0	0
IT	378.66	0	0	0	0	0

Benelux

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	855.61	0	0	0	0
O	0	0	0	0	0	0
UK	0	0	0	0	0	0
IT	0	0	0	0	0	0

Iberia

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	0	0	0	0	0
O	0	0	0	0	0	0
UK	0	0	0	0	0	0
IT	0	0	0	0	0	0

Table A7.4. EWI-01: increased competition DATA NEG-TPA (continued)

EWI-01 : increased competition DATA NEG-TPA

Germany

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0	0
F	6375	7182	9775	9775	9775	9775	9775
A	18935	18935	18935	18935	18935	18935	18935
L	10104	10104	10104	10104	10104	10104	10104
IB	0	0	0	0	0	0	0
N	2235	3435	3435	4761	4761	4761	4761
O	5100	5100	5394	5419	5448	5485	5491
UK	0	0	0	0	0	0	0
IT	0	0	0	0	0	0	0

France

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	6375	6375	6375	6375	6375	6375	6375
F	0	0	0	0	0	0	0
A	5335	5616	7335	7335	7335	7335	7335
L	3335	4723	5335	5335	5335	5335	5335
IB	3429	3429	3429	3429	3429	3429	3429
N	0	0	0	0	0	0	0
O	0	0	0	0	0	0	0
UK	2000	2042	2042	2049	2123	2168	2168
IT	4290	4290	4290	4290	4290	4290	4290

Austria and Switzerland

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	18935	18935	18935	18935	18935	18935	18935
F	5335	5335	5335	5335	5335	5335	5335
A	0	0	0	0	0	0	0
L	0	0	0	0	0	0	0
IB	0	0	0	0	0	0	0
N	0	0	0	0	0	0	0
O	2104	2704	2704	3371	3371	3371	3371
UK	0	0	0	0	0	0	0
IT	3982	4361	4361	4361	4361	4361	4361

Benelux

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	10104	10104	10104	10104	10104	10104	10104
F	3335	3335	3335	3335	3335	3335	3335
A	0	0	0	0	0	0	0
L	0	0	0	0	0	0	0
IB	0	0	0	0	0	0	0
N	0	0	856	856	856	856	856
O	0	0	0	0	0	0	0
UK	0	0	0	0	0	0	0
IT	0	0	0	0	0	0	0

Iberia

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0	0
F	3429	3429	3429	3429	3429	3429	3429
A	0	0	0	0	0	0	0
L	0	0	0	0	0	0	0
IB	0	0	0	0	0	0	0
N	0	0	0	0	0	0	0
O	0	0	0	0	0	0	0
UK	0	0	0	0	0	0	0
IT	0	0	0	0	0	0	0

Table A7.5. Capacity utilization of generation plant per hour by year

nTPA

Germany

	1995	2000	2005	2010	2015	2020
HC	5214	6805	6621	7104	7117	7148
HCGUD	0	0	0	7617	7617	7617
HCGAS	0	0	7442	6292	6762	6762
BC	6310	6429	6124	6235	7426	7437
OIL	0	0	0	0	0	0
GASGUD	0	7530	7157	5338	4887	4453
GASTUR	351	339	254	226	211	0
NUC	6950	6950	6949	6946	6937	6933

France

	1995	2000	2005	2010	2015	2020
HC	1892	1889	1681	3831	6125	6519
HCGUD	0	0	0	0	0	0
HCGAS	0	0	0	0	0	0
OIL	0	0	0	0	0	0
GASGUD	0	2288	1050	240	571	1367
GASTUR	5685	5688	5963	6249	6285	6293

Austria/Switzerland

	1995	2000	2005	2010	2015	2020
HC	1950	2879	3338	5803	5541	5785
HCGUD	0	0	0	0	0	0
HCGAS	0	0	0	0	0	0
BC	5062	1892	1485	2113	0	0
OIL	0	0	0	0	0	0
GASGUD	0	0	3229	1856	1838	984
GASTUR	7530	7530	7524	7518	7513	7513

Benelux

	1995	2000	2005	2010	2015	2020
HC	6681	6799	7178	7174	7171	7166
HCGUD	0	0	0	0	0	0
HCGAS	7442	7442	5272	7442	6028	6027
OIL	0	0	0	0	0	0
GASGUD	7880	7518	5845	4665	4393	4955
GASTUR	7530	7530	7530	7522	7519	7515

Iberia

	1995	2000	2005	2010	2015	2020
HC	4281	6003	6288	6705	7158	7157
HCGUD	0	0	0	0	0	0
HCGAS	0	0	0	0	0	0
BC	6752	7324	7090	7113	0	0
OIL	0	275	843	0	0	0
GASGUD	0	0	4322	4600	4665	5868
GASTUR	7530	7530	7529	7527	7530	7504

Table A7.6. NTPA share of new technologies

New. Tech: GTCC & IGCC

German capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	6497	9095	15421	26579	38575	59792
Conv.Tech.	80971	77622	77396	73521	66575	55742
Sum	87468	86717	92817	100100	105150	115534

German capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	7.43	10.49	16.61	26.55	36.69	51.75
Conv.Tech.	92.57	89.51	83.39	73.45	63.31	48.25
Sum	100	100	100	100	100	100

French capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	657	2000	2982	11103	11103	11103
Conv.Tech.	105844	104512	103185	99123	99063	100964
Sum	106501	106512	106167	110226	110166	112067

French capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	0.62	1.88	2.81	10.07	10.08	9.91
Conv.Tech.	99.38	98.12	97.19	89.93	89.92	90.09
Sum	100	100	100	100	100	100

Austrian/Swiss capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	0	152	2112	2520	2879	2879
Conv.Tech.	32404	32984	33972	34781	35813	37153
Sum	32404	33136	36084	37301	38692	40032

Austrian/Swiss capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	0.00	0.46	5.85	6.76	7.44	7.19
Conv.Tech.	100.00	99.54	94.15	93.24	92.56	92.81
Sum	100	100	100	100	100	100

Benelux capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	9327	7512	9543	12790	18205	17763
Conv.Tech.	20608	22852	21997	22307	21993	21195
Sum	29935	30364	31540	35097	40198	38958

Table A7.6. NTPA share of new technologies (continued)

Benelux capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	31.16	24.74	30.26	36.44	45.29	45.60
Conv.Tech.	68.84	75.26	69.74	63.56	54.71	54.40
Sum	100	100	100	100	100	100

Iberian capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	0	0	1333	6727	12667	18412
Conv.Tech.	50975	49761	49446	46507	44435	41095
Sum	50975	49761	50778	53234	57102	59507

Iberian capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	0.00	0.00	2.62	12.64	22.18	30.94
Conv.Tech.	100.00	100.00	97.38	87.36	77.82	69.06
Sum	100	100	100	100	100	100

Table A7.7. Grid utilization

Capacity utilization of networks [real/theoretical]

Grid-utilization: Actual flows [TWh]/Maximum flow capacity [TWh]

CAPR-01 = nTPA

1994 (act.)

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.13	0.38	0.00	0.20	0.02	0.00	0.00
F	0.54	0.00	0.33	0.32	0.25	0.00	0.00	0.00	0.01
A	0.13	0.03	0.00	0.00	0.00	0.00	0.34	0.00	0.00
L	0.03	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IB	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.20	0.00	0.00	0.00	0.00				
O	0.02	0.00	0.34	0.00	0.00				
UK	0.00	0.00	0.00	0.00	0.00				
IT	0.00	0.01	0.00	0.00	0.00				

1995

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.06	0.10	0.00	0.29	0.04	0.00	0.00
F	0.93	0.00	0.73	0.65	0.71	0.00	0.00	0.03	0.00
A	0.14	0.00	0.00	0.00	0.00	0.00	0.28	0.00	0.03
L	0.04	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IB	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.29	0.00	0.00	0.00	0.00				
O	0.04	0.00	0.28	0.00	0.00				
UK	0.00	0.03	0.00	0.00	0.00				
IT	0.00	0.00	0.03	0.00	0.00				

2000

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.12	0.11	0.00	0.29	0.05	0.00	0.00
F	0.75	0.00	0.77	0.76	0.44	0.00	0.00	0.07	0.00
A	0.19	0.00	0.00	0.00	0.00	0.00	0.39	0.00	0.04
L	0.34	0.02	0.00	0.00	0.00	0.29	0.00	0.00	0.00
IB	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.29	0.00	0.00	0.29	0.00				
O	0.05	0.00	0.39	0.00	0.00				
UK	0.00	0.07	0.00	0.00	0.00				
IT	0.00	0.00	0.04	0.00	0.00				

2005

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.07	0.12	0.00	0.29	0.17	0.00	0.00
F	0.73	0.00	0.65	0.62	0.47	0.00	0.00	0.08	0.01
A	0.21	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.04
L	0.13	0.02	0.00	0.00	0.00	0.30	0.00	0.00	0.00
IB	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.29	0.00	0.00	0.30	0.00				
O	0.17	0.00	0.33	0.00	0.00				
UK	0.00	0.08	0.00	0.00	0.00				
IT	0.00	0.01	0.04	0.00	0.00				

2010

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.08	0.13	0.00	0.32	0.20	0.00	0.00
F	0.72	0.00	0.53	0.54	0.42	0.00	0.00	0.09	0.01
A	0.19	0.00	0.00	0.00	0.00	0.00	0.38	0.00	0.05
L	0.10	0.02	0.00	0.00	0.00	0.31	0.00	0.00	0.00
IB	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.32	0.00	0.00	0.31	0.00				
O	0.20	0.00	0.38	0.00	0.00				
UK	0.00	0.09	0.00	0.00	0.00				
IT	0.00	0.01	0.05	0.00	0.00				

Table A7.7. Grid utilization (continued)

2015

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.11	0.14	0.00	0.32	0.22	0.00	0.00
F	0.63	0.00	0.53	0.36	0.34	0.00	0.00	0.09	0.05
A	0.17	0.00	0.00	0.00	0.00	0.00	0.35	0.00	0.01
L	0.16	0.08	0.00	0.00	0.00	0.32	0.00	0.00	0.00
IB	0.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.32	0.00	0.00	0.32	0.00				
O	0.22	0.00	0.35	0.00	0.00				
UK	0.00	0.09	0.00	0.00	0.00				
IT	0.00	0.05	0.01	0.00	0.00				

2020

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.16	0.16	0.00	0.32	0.18	0.00	0.00
F	0.47	0.00	0.38	0.37	0.32	0.00	0.00	0.09	0.05
A	0.15	0.03	0.00	0.00	0.00	0.00	0.43	0.00	0.01
L	0.10	0.09	0.00	0.00	0.00	0.34	0.00	0.00	0.00
IB	0.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.32	0.00	0.00	0.34	0.00				
O	0.18	0.00	0.43	0.00	0.00				
UK	0.00	0.09	0.00	0.00	0.00				
IT	0.00	0.05	0.01	0.00	0.00				

A8. TPA

Table A8.1. TPA power generation forecasts for Europe

Power generation by fuel in TWh
Germany

	1993 (act.)	2000	2005	2010	2015	2020
HC	99	111	133	149	152	224
BC	117	134	138	140	122	87
OIL	3	0	0	0	0	0
GAS	15	39	70	93	141	158
NUC	144	145	145	145	145	145
HYDRO	19	20	21	21	22	23
Sum	397	450	507	549	581	637

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Germany

	1993 (act.)	2000	2005	2010	2015	2020
HC	25	25	26	27	26	35
BC	30	30	27	26	21	14
OIL	1	0	0	0	0	0
GAS	4	9	14	17	24	25
NUC	36	32	29	26	25	23
HYDRO	5	4	4	4	4	4
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
France

	1993 (act.)	2000	2005	2010	2015	2020
HC	20	27	32	32	34	27
OIL	4	0	0	0	0	0
GAS	7	5	3	16	17	18
NUC	350	405	406	409	404	416
HYDRO	72	96	97	95	93	92
Sum	453	533	537	551	548	553

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
France

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	5	6	6	6	5
OIL	1	0	0	0	0	0
GAS	2	1	1	3	3	3
NUC	77	76	76	74	74	75
HYDRO	16	18	18	17	17	17
Sum	100	100	100	100	100	100

Table A8.1. TPA power generation forecasts for Europe (continued)

Power generation by fuel in TWh
Benelux

	1993 (act.)	2000	2005	2010	2015	2020
HC	37	71	60	59	53	44
OIL	1	0	0	0	0	0
GAS	57	36	45	55	82	86
NUC	43	44	44	44	43	43
HYDRO	2	2	2	2	2	2
Sum	140	153	151	160	181	175

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Benelux

	1993 (act.)	2000	2005	2010	2015	2020
HC	27	46	40	37	29	25
OIL	1	0	0	0	0	0
GAS	40	24	30	35	45	49
NUC	31	28	29	27	24	25
HYDRO	1	1	1	1	1	1
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
Austria/Switzerland

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	4	8	9	7	7
BC	1	1	2	2	2	1
OIL	2	0	0	0	0	0
GAS	7	0	5	5	5	5
NUC	22	22	22	22	22	22
HYDRO	74	71	71	78	82	88
Sum	110	98	107	115	117	122

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Austria/Switzerland

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	4	7	8	6	5
BC	1	1	1	2	1	1
OIL	2	0	0	0	0	0
GAS	6	0	4	4	4	4
NUC	20	22	20	19	18	18
HYDRO	67	72	67	67	70	72
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
Portugal/Spain

	1993 (act.)	2000	2005	2010	2015	2020
HC	56	56	64	66	72	39
BC	12	13	13	13	1	1
OIL	10	2	3	0	0	0
GAS	0	0	8	31	61	108
NUC	53	56	56	56	56	56
HYDRO	31	42	42	43	45	46
Sum	162	170	186	208	234	250

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Portugal/Spain

	1993 (act.)	2000	2005	2010	2015	2020
HC	35	33	34	32	31	16
BC	7	8	7	6	0	0
OIL	6	1	1	0	0	0
GAS	0	0	5	15	26	43
NUC	33	33	30	27	24	22
HYDRO	19	25	23	21	19	18
Sum	100	100	100	100	100	100

Table A8.2. TPA power capacity forecasts for Europe

German capacity development [MW]

	1993 (act.)	2000	2005	2010	2015	2020
HC	23328	19401	20351	20752	20861	29976
BC	20139	20858	22538	22538	17182	11681
OIL	5435	2174	1441	544	310	285
GAS	10448	12544	18804	25546	35522	42604
NUC	22507	20866	20866	20866	20866	20866
HYDRO	8250	8607	8817	9171	9524	9878
Sum	90106	84450	92817	99417	104265	115290

French capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	11840	9973	8081	5113	5113	4003
OIL	6262	3323	2796	841	685	685
GAS	1699	3915	4972	14366	14528	14697
NUC	57675	64795	64795	64795	64022	66157
HYDRO	24996	24636	24636	25343	26050	26757
Sum	102472	106642	105280	110458	110398	112299

Austrian/Swiss capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	1517	2226	2226	1420	994	994
BC	460	742	742	742	605	275
OIL	3649	692	692	650	619	574
GAS	570	2492	4927	5617	5927	6267
NUC	2950	2868	2868	2868	2868	2868
HYDRO	22826	24116	24629	26004	27378	28753
Sum	31972	33136	36084	37301	38391	39731

Benelux capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	7536	10255	8467	8275	7408	6161
OIL	1112	574	574	574	574	414
GAS	11587	11112	14321	18070	24563	24730
NUC	5990	5785	5785	5785	5785	5785
HYDRO	2562	2393	2393	2393	2393	2393
Sum	28787	30119	31540	35097	40723	39483

Iberian capacity development [MW]

	1994 (act.)	2000	2005	2010	2015	2020
HC	9152	9955	10860	10102	10043	5505
BC	1800	2150	2150	1830	134	134
OIL	7886	6858	5083	1680	100	0
GAS	3902	2775	5235	10848	17154	22628
NUC	7400	7400	7400	7400	7400	7400
HYDRO	20324	20937	20937	21832	22729	23624
Sum	52064	50075	51665	53692	57560	59291

Table A8.3. TPA forecasts for European net imports

Net-power imports 1993 (net imports + net exports); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	13.362	-3.554	-13.841	0	2.88	0.826	0	0
F	-13.362	0	-8.912	-2.768	-1.570	0	0	-16.759	-17.279
A / CH	3.554	8.912	0	0	0	0	2.495	0	-21.201
Benelux	13.841	2.768	0	0	0	0	0	0	0
IB	0	1.570	0	0	0				
Scand.	-2.88	0	0	0	0				
Ost-E.	-0.826	0	-2.495	0	0				
UK	0	16.759	0	0	0				
I	0	17.279	21.201	0	0				

Net-power imports 1995 (net imports + net exports); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	44.958	14.297	3.822	0	6.5	0.559	0	0
F	-44.958	0	-26.624	-22.331	-18.189	0	0	-14.282	-12.624
A / CH	-14.297	26.624	0	0	0	0	2.192	0	-15.637
Benelux	-3.822	22.331	0	0	0	0	0	0	0
IB	0	18.189	0	0	0				
Scand.	-6.5	0	0	0	0				
Ost-E.	-0.559	0	-2.192	0	0				
UK	0	14.282	0	0	0				
I	0	12.624	15.637	0	0				

Net-power imports 2000 (net imports + net exports); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	48.772	15.325	24.253	0	3.425	1.64	0	0
F	-48.772	0	-38.709	-30.314	-9.183	0	0	-13.882	-9.800
A / CH	-15.325	38.709	0	0	0	0	2.692	0	-11.967
Benelux	-24.253	30.314	0	0	0	-1.731	0	0	0
IB	0	9.183	0	0	0				
Scand.	-3.425	0	0	1.731	0				
Ost-E.	-1.64	0	-2.692	0	0				
UK	0	13.882	0	0	0				
I	0	9.800	11.967	0	0				

Net-power imports 2005 (net imports + net exports-); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	45.901	18.452	5.463	0	4.451	3.359	0	0
F	-45.901	0	-30.512	-23.587	-9.520	0	0	-13.782	-3.078
A / CH	-18.452	30.512	0	0	0	0	3.697	0	-3.042
Benelux	-5.463	23.587	0	0	0	-1.662	0	0	0
IB	0	9.520	0	0	0				
Scand.	-4.451	0	0	1.662	0				
Ost-E.	-3.359	0	-3.697	0	0				
UK	0	13.782	0	0	0				
I	0	3.078	3.042	0	0				

Table A8.3. TPA forecasts for European net imports (continued)

Net-power imports 2010 (net imports + net exports-); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	44.282	16.973	1.65	0	3.771	3.781	0	0
F	-44.282	0	-22.564	-19.717	-8.701	0	0	-13.682	-1.498
A / CH	-16.973	22.564	0	0	0	0	4.676	0	-1.014
Benelux	-1.65	19.717	0	0	0	-1.581	0	0	0
IB	0	8.701	0	0	0				
Scand.	-3.771	0	0	1.581	0				
Ost-E.	-3.781	0	-4.676	0	0				
UK	0	13.682	0	0	0				
I	0	1.498	1.014	0	0				

Net-power imports 2015 (net imports + net exports); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	36.111	12.159	6.564	0	3.817	4.406	0	0
F	-36.111	0	-21.618	-9.712	-1.986	0	0	-13.582	-0.718
A / CH	-12.159	21.618	0	0	0	0	3.911	0	-1.794
Benelux	-6.564	9.712	0	0	0	-1.487	0	0	0
IB	0	1.986	0	0	0				
Scand.	-3.817	0	0	1.487	0				
Ost-E.	-4.406	0	-3.911	0	0				
UK	0	13.582	0	0	0				
I	0	0.718	1.794	0	0				

Net-power imports 2020 (net imports + net exports); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0	21.418	2.655	-0.107	0	3.86	3.409	0	0
F	-21.418	0	-9.905	-11.182	-2.644	0	0	-13.582	-0.718
A / CH	-2.655	9.905	0	0	0	0	4.996	0	-1.794
Benelux	0.107	11.182	0	0	0	-1.382	0	0	0
IB	0	2.644	0	0	0				
Scand.	-3.86	0	0	1.382	0				
Ost-E.	-3.409	0	-4.996	0	0				
UK	0	13.582	0	0	0				
I	0	0.718	1.794	0	0				

Table A8.4. EWI: full competition DATA TPA

Transmission capacity additions

Germany

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	5000	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	1200	0	1326.17	0	0	0
O	0	0	318.8	28.81	37.04	6.17
UK	0	0	0	0	0	0
IT	0	0	0	0	0	0

France

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	4214.25	0	0	0	0	0
L	5000	0	0	0	0	0
IB	1479.34	0	0	0	0	0
N	0	0	0	0	0	0
O	0	0	0	0	0	0
UK	42.01	0	25.5	55.34	10.41	0
IT	0	0	0	0	0	0

Austria and Switzerland

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	0	0	0	0	0
O	600	0	667.43	0	0	0
UK	0	0	0	0	0	0
IT	378.66	0	0	0	0	0

Benelux

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	855.61	0	0	0	0
O	0	0	0	0	0	0
UK	0	0	0	0	0	0
IT	0	0	0	0	0	0

Iberia

	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0
F	0	0	0	0	0	0
A	0	0	0	0	0	0
L	0	0	0	0	0	0
IB	0	0	0	0	0	0
N	0	0	0	0	0	0
O	0	0	0	0	0	0
UK	0	0	0	0	0	0
IT	0	0	0	0	0	0

Table A8.4. EWI: full competition DATA TPA (continued)

EWI-VH : full competition DATA TPA

Germany

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0	0
F	6375	11375	11375	11375	11375	11375	11375
A	18935	18935	18935	18935	18935	18935	18935
L	10104	10104	10104	10104	10104	10104	10104
IB	0	0	0	0	0	0	0
N	2235	3435	3435	4761	4761	4761	4761
O	5100	5100	5100	5419	5448	5485	5491
UK	0	0	0	0	0	0	0
IT	0	0	0	0	0	0	0

France

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	6375	6375	6375	6375	6375	6375	6375
F	0	0	0	0	0	0	0
A	5335	9549	9549	9549	9549	9549	9549
L	3335	8335	8335	8335	8335	8335	8335
IB	3429	4908	4908	4908	4908	4908	4908
N	0	0	0	0	0	0	0
O	0	0	0	0	0	0	0
UK	2000	2042	2042	2068	2123	2133	2133
IT	4290	4290	4290	4290	4290	4290	4290

Austria and Switzerland

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	18935	18935	18935	18935	18935	18935	18935
F	5335	5335	5335	5335	5335	5335	5335
A	0	0	0	0	0	0	0
L	0	0	0	0	0	0	0
IB	0	0	0	0	0	0	0
N	0	0	0	0	0	0	0
O	2104	2704	2704	3371	3371	3371	3371
UK	0	0	0	0	0	0	0
IT	3982	4361	4361	4361	4361	4361	4361

Benelux

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	10104	10104	10104	10104	10104	10104	10104
F	3335	3335	3335	3335	3335	3335	3335
A	0	0	0	0	0	0	0
L	0	0	0	0	0	0	0
IB	0	0	0	0	0	0	0
N	0	0	856	856	856	856	856
O	0	0	0	0	0	0	0
UK	0	0	0	0	0	0	0
IT	0	0	0	0	0	0	0

Iberia

	1993 (Ist)	1995	2000	2005	2010	2015	2020
G	0	0	0	0	0	0	0
F	3429	3429	3429	3429	3429	3429	3429
A	0	0	0	0	0	0	0
L	0	0	0	0	0	0	0
IB	0	0	0	0	0	0	0
N	0	0	0	0	0	0	0
O	0	0	0	0	0	0	0
UK	0	0	0	0	0	0	0
IT	0	0	0	0	0	0	0

Table A8.5. Capacity utilization of generation plant per hour by year

TPA

Germany

	1995	2000	2005	2010	2015	2020
HC	4489	5745	6523	7103	7159	7148
HCGUD	0	0	0	7617	7617	7617
HCGAS	0	0	6762	6762	6762	6762
BC	5847	6427	6120	6232	7092	7437
OIL	0	0	0	0	0	0
GASGUD	0	7530	5899	4411	4548	4183
GASTUR	351	339	254	226	211	0
NUC	6950	6950	6949	6946	6937	6933

France

	1995	2000	2005	2010	2015	2020
HC	1884	2656	3915	6365	6796	6984
HCGUD	0	0	0	0	0	0
HCGAS	6028	0	0	0	0	0
OIL	0	0	0	0	0	0
GASGUD	0	3568	1541	1383	1483	1569
GASTUR	6270	6246	6269	6305	6306	6294

Austrian/Swiss

	1995	2000	2005	2010	2015	2020
HC	1946	1697	3529	6510	7179	6490
HCGUD	0	0	0	0	0	0
HCGAS	0	0	0	0	0	0
BC	5027	1892	2113	2991	2583	5089
OIL	0	0	0	0	0	0
GASGUD	0	0	2147	1858	1856	1856
GASTUR	7530	7530	7524	7518	7513	7513

Benelux

	1995	2000	2005	2010	2015	2020
HC	6517	6929	7147	7171	7171	7166
HCGUD	0	0	0	0	0	0
HCGAS	7442	7442	5272	6028	6028	6027
OIL	0	0	0	0	0	0
GASGUD	7756	7530	5567	4349	4411	4707
GASTUR	7530	7530	7530	7522	7519	7515

Iberian

	1995	2000	2005	2010	2015	2020
HC	3519	5662	5890	6517	7158	7157
HCGUD	0	0	0	0	0	0
HCGAS	0	0	0	0	0	0
BC	6752	6243	6048	7113	0	0
OIL	0	337	535	0	0	0
GASGUD	0	0	4251	4231	4633	5947
GASTUR	7530	7530	7529	7527	7530	7504

Table A8.6. TPA share of new technologies

New technologies: GTCC and IGCC

German capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	6497	9095	15421	25896	37690	59548
Conv.Tech.	80971	75355	77396	73521	66575	55742
Sum	87468	84450	92817	99417	104265	115290

German capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	7.43	10.77	16.61	26.05	36.15	51.65
Conv.Tech.	92.57	89.23	83.39	73.95	63.85	48.35
Sum	100	100	100	100	100	100

French capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	657	2000	2095	11335	11335	11335
Conv.Tech.	105844	104642	103185	99123	99063	100964
Sum	106501	106642	105280	110458	110398	112299

French capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	0.62	1.88	1.99	10.26	10.27	10.09
Conv.Tech.	99.38	98.12	98.01	89.74	89.73	89.91
Sum	100	100	100	100	100	100

Austrian/Swiss capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	0	152	2112	2520	2578	2578
Conv.Tech.	32404	32984	33972	34781	35813	37153
Sum	32404	33136	36084	37301	38391	39731

Austrian/Swiss capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	0.00	0.46	5.85	6.76	6.72	6.49
Conv.Tech.	100.00	99.54	94.15	93.24	93.28	93.51
Sum	100	100	100	100	100	100

Table A8.6. TPA share of new technologies (continued)

Benelux capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	9327	7512	9543	12790	18730	18288
Conv.Tech.	20608	22607	21997	22307	21993	21195
Sum	29935	30119	31540	35097	40723	39483

Benelux capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	31.16	24.94	30.26	36.44	45.99	46.32
Conv.Tech.	68.84	75.06	69.74	63.56	54.01	53.68
Sum	100	100	100	100	100	100

Iberian capacity development of new technologies [MW]

	1995	2000	2005	2010	2015	2020
New Tech.	0	0	1905	7185	13125	18196
Conv.Tech.	50975	50075	49760	46507	44435	41095
Sum	50975	50075	51665	53692	57560	59291

Iberian capacity development of new technologies [%]

	1995	2000	2005	2010	2015	2020
New Tech.	0.00	0.00	3.69	13.38	22.80	30.69
Conv.Tech.	100.00	100.00	96.31	86.62	77.20	69.31
Sum	100	100	100	100	100	100

Table A8.7. TPA grid utilization

Grid-utilization: actual flows [TWh]/maximum flow capacity [TWh]

CAPR-vh = TPA

1994 (act.)

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.13	0.38	0.00	0.20	0.02	0.00	0.00
F	0.54	0.00	0.33	0.32	0.25	0.00	0.00	0.00	0.01
A	0.13	0.03	0.00	0.00	0.00	0.00	0.34	0.00	0.00
L	0.03	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IB	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.20	0.00	0.00	0.00	0.00				
O	0.02	0.00	0.34	0.00	0.00				
UK	0.00	0.00	0.00	0.00	0.00				
IT	0.00	0.01	0.00	0.00	0.00				

1995

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.04	0.10	0.00	0.29	0.05	0.00	0.00
F	0.90	0.00	0.64	0.62	0.86	0.00	0.00	0.06	0.03
A	0.22	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.00
L	0.18	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IB	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.29	0.00	0.00	0.00	0.00				
O	0.05	0.00	0.27	0.00	0.00				
UK	0.00	0.06	0.00	0.00	0.00				
IT	0.00	0.03	0.00	0.00	0.00				

2000

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.08	0.11	0.00	0.29	0.10	0.00	0.00
F	0.98	0.00	0.93	0.84	0.47	0.00	0.00	0.08	0.02
A	0.26	0.00	0.00	0.00	0.00	0.00	0.31	0.00	0.01
L	0.66	0.01	0.00	0.00	0.00	0.30	0.00	0.00	0.00
IB	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.29	0.00	0.00	0.30	0.00				
O	0.10	0.00	0.31	0.00	0.00				
UK	0.00	0.08	0.00	0.00	0.00				
IT	0.00	0.02	0.01	0.00	0.00				

2005

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.06	0.12	0.00	0.29	0.17	0.00	0.00
F	0.92	0.00	0.73	0.66	0.51	0.00	0.00	0.08	0.01
A	0.28	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.04
L	0.24	0.01	0.00	0.00	0.00	0.31	0.00	0.00	0.00
IB	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.29	0.00	0.00	0.31	0.00				
O	0.17	0.00	0.33	0.00	0.00				
UK	0.00	0.08	0.00	0.00	0.00				
IT	0.00	0.01	0.04	0.00	0.00				

2010

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.06	0.13	0.00	0.32	0.19	0.00	0.00
F	0.89	0.00	0.54	0.56	0.43	0.00	0.00	0.09	0.01
A	0.26	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.05
L	0.17	0.01	0.00	0.00	0.00	0.32	0.00	0.00	0.00
IB	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.32	0.00	0.00	0.32	0.00				
O	0.19	0.00	0.40	0.00	0.00				
UK	0.00	0.09	0.00	0.00	0.00				
IT	0.00	0.01	0.05	0.00	0.00				

Table A8.7. TPA grid utilization (continued)

2015

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.07	0.15	0.00	0.32	0.22	0.00	0.00
F	0.72	0.00	0.52	0.32	0.29	0.00	0.00	0.09	0.05
A	0.22	0.00	0.00	0.00	0.00	0.00	0.35	0.00	0.01
L	0.30	0.05	0.00	0.00	0.00	0.33	0.00	0.00	0.00
IB	0.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.32	0.00	0.00	0.33	0.00				
O	0.22	0.00	0.35	0.00	0.00				
UK	0.00	0.09	0.00	0.00	0.00				
IT	0.00	0.05	0.01	0.00	0.00				

2020

	G	F	A	L	IB	N	O	UK	IT
G	0.00	0.00	0.13	0.18	0.00	0.32	0.18	0.00	0.00
F	0.43	0.00	0.28	0.35	0.26	0.00	0.00	0.09	0.05
A	0.16	0.04	0.00	0.00	0.00	0.00	0.43	0.00	0.01
L	0.18	0.05	0.00	0.00	0.00	0.34	0.00	0.00	0.00
IB	0.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	0.32	0.00	0.00	0.34	0.00				
O	0.18	0.00	0.43	0.00	0.00				
UK	0.00	0.09	0.00	0.00	0.00				
IT	0.00	0.05	0.01	0.00	0.00				

A9. High gas demand

Table A9.1. Power generation forecasts under high gas demand

Power generation by fuel in TWh: high gas case
Germany

	1993 (act.)	2000	2005	2010	2015	2020
HC	99	103	105	132	119	93
BC	117	134	131	78	35	5
OIL	3	0	0	0	0	0
GAS	15	42	95	133	200	269
NUC	144	145	145	145	145	145
HYDRO	19	20	21	21	22	23
Sum	397	444	497	510	521	535

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Germany

	1993 (act.)	2000	2005	2010	2015	2020
HC	25	23	21	26	23	17
BC	30	30	26	15	7	1
OIL	1	0	0	0	0	0
GAS	4	10	19	26	38	50
NUC	36	33	29	28	28	27
HYDRO	5	4	4	4	4	4
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
France

	1993 (act.)	2000	2005	2010	2015	2020
HC	20	23	18	24	25	21
OIL	4	0	0	0	0	0
GAS	7	10	26	54	76	77
NUC	350	405	407	409	404	416
HYDRO	72	96	96	95	93	92
Sum	453	535	548	582	598	606

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
France

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	4	3	4	4	3
OIL	1	0	0	0	0	0
GAS	2	2	5	9	13	13
NUC	77	76	74	70	68	69
HYDRO	16	18	18	16	16	15
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
Benelux

	1993 (act.)	2000	2005	2010	2015	2020
HC	37	59	50	56	49	37
OIL	1	0	0	0	0	0
GAS	57	56	66	84	119	160
NUC	43	44	44	44	43	43
HYDRO	2	2	2	2	2	2
Sum	140	161	161	185	214	243

Table A9.1. Power generation forecasts under high gas demand (continued)

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Benelux

	1993 (act.)	2000	2005	2010	2015	2020
HC	27	37	31	30	23	15
OIL	1	0	0	0	0	0
GAS	40	35	41	45	56	66
NUC	31	27	27	24	20	18
HYDRO	1	1	1	1	1	1
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
Austria/Switzerland

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	2	6	7	5	5
BC	1	1	1	1	1	0
OIL	2	0	0	0	0	0
GAS	7	1	0	3	1	1
NUC	22	22	22	22	22	22
HYDRO	74	70	71	77	82	86
Sum	110	96	100	109	110	114

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Austria/Switzerland

	1993 (act.)	2000	2005	2010	2015	2020
HC	4	2	6	6	4	4
BC	1	1	1	1	1	0
OIL	2	0	0	0	0	0
GAS	6	1	0	3	1	1
NUC	20	23	22	20	20	19
HYDRO	67	73	71	71	74	76
Sum	100	100	100	100	100	100

Power generation by fuel in TWh
Portugal/Spain

	1993 (act.)	2000	2005	2010	2015	2020
HC	56	56	61	56	50	39
BC	12	14	13	7	1	0
OIL	10	0	1	0	0	0
GAS	0	1	9	38	70	100
NUC	53	56	56	56	56	56
HYDRO	31	42	42	43	45	46
Sum	162	168	182	200	221	241

Power generation by fuel in per cent (sum of figures may not total 100 due to rounding)
Portugal/Spain

	1993 (act.)	2000	2005	2010	2015	2020
HC	35	33	34	28	23	16
BC	7	8	7	3	0	0
OIL	6	0	0	0	0	0
GAS	0	0	5	19	32.	41
NUC	33	33	31	28	25	23
HYDRO	19	25	23	22	20	19
Sum	100	100	100	100	100	100

Table A9.2. Power capacity forecasts under high gas demand

German capacity development [MW]

	1993 (act.)	2000	2005	2010	2015	2020
HC	23328	19401	20351	18871	16935	12830
BC	20139	20858	22538	22538	17182	11681
OIL	5435	2174	1441	544	310	285
GAS	10448	12544	18804	25546	35522	46321
NUC	22507	20866	20866	20866	20866	20866
HYDRO	8250	8607	8817	9171	9524	9878
Sum	90106	84450	92817	97536	100339	101861

French capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	11840	9973	8081	5113	5113	4003
OIL	6262	3323	2796	841	685	685
GAS	1699	3915	7079	16473	19225	21168
NUC	57675	64795	64795	64795	64022	66157
HYDRO	24996	24636	24636	25343	26050	26757
Sum	102472	106642	107387	112565	115095	118770

Austrian/Swiss capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	1517	2226	2226	1420	994	994
BC	460	742	742	742	605	275
OIL	3649	692	692	650	619	574
GAS	570	2492	2967	5617	5927	6267
NUC	2950	2868	2868	2868	2868	2868
HYDRO	22826	24116	24629	26004	27378	28753
Sum	31972	33136	34124	37301	38391	39731

Benelux capacity development [MW]

	1992 (act.)	2000	2005	2010	2015	2020
HC	7536	8467	8467	8275	7408	6161
OIL	1112	574	574	574	574	414
GAS	11587	12914	14321	18070	24563	31330
NUC	5990	5785	5785	5785	5785	5785
HYDRO	2562	2393	2393	2393	2393	2393
Sum	28787	30133	31540	35097	40723	46083

Iberian capacity development [MW]

	1994 (act.)	2000	2005	2010	2015	2020
HC	9152	10465	11370	10452	10043	5505
BC	1800	2122	2122	1990	590	590
OIL	7886	6858	5083	1680	100	0
GAS	3902	2775	4697	10310	16143	23146
NUC	7400	7400	7400	7400	7400	7400
HYDRO	20324	20937	20937	21832	22729	23624
Sum	52064	50557	51610	53664	57005	60265

Table A9.3. Forecasts for European net imports under high gas demand

Net-power imports 1994 (net imports+, net exports-); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0.0	14.9	-0.1	-15.6	0.0	2.7	0.3	0.0	0.0
F	-14.9	0.0	-7.1	-3.3	-2.8	0.0	0.0	-16.9	-17.1
A / CH	0.1	7.1	0.0	0.0	0.0	0.0	2.5	0.0	-20.6
Benelux	15.6	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IB	0.0	2.8	0.0	0.0	0.0				
Scand.	-2.7	0.0	0.0	0.0	0.0				
Ost-E.	-0.3	0.0	-2.5	0.0	0.0				
UK	0.0	16.9	0.0	0.0	0.0				
I	0.0	17.1	20.6	0.0	0.0				

Net-power imports 1995 (net imports+, net exports-); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0.0	44.2	14.9	3.4	0.0	6.5	0.8	0.0	0.0
F	-44.2	0.0	-27.5	-21.7	-19.1	0.0	0.0	-14.3	-12.6
A / CH	-14.9	27.5	0.0	0.0	0.0	0.0	1.9	0.0	-15.6
Benelux	-3.4	21.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IB	0.0	19.1	0.0	0.0	0.0				
Scand.	-6.5	0.0	0.0	0.0	0.0				
Ost-E.	-0.8	0.0	-1.9	0.0	0.0				
UK	0.0	14.3	0.0	0.0	0.0				
I	0.0	12.6	15.6	0.0	0.0				

Net-power imports 2000 (net imports+, net exports-); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0.0	48.8	14.9	29.9	0.0	3.5	1.6	0.0	0.0
F	-48.8	0.0	-40.2	-28.4	-11.2	0.0	0.0	-13.9	-9.8
A / CH	-14.9	40.2	0.0	0.0	0.0	0.0	2.7	0.0	-12.0
Benelux	-29.9	28.4	0.0	0.0	0.0	-1.8	0.0	0.0	0.0
IB	0.0	11.2	0.0	0.0	0.0				
Scand.	-3.5	0.0	0.0	1.8	0.0				
Ost-E.	-1.6	0.0	-2.7	0.0	0.0				
UK	0.0	13.9	0.0	0.0	0.0				
I	0.0	9.8	12.0	0.0	0.0				

Net-power imports 2005 (net imports+, net exports-); TWh

Export	Import								
	D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0.0	47.7	15.0	17.0	0.0	4.5	3.4	0.0	0.0
F	-47.7	0.0	-34.3	-24.8	-13.4	0.0	0.0	-13.8	-2.4
A / CH	-15.0	34.3	0.0	0.0	0.0	0.0	3.7	0.0	-3.7
Benelux	-17.0	24.8	0.0	0.0	0.0	-1.7	0.0	0.0	0.0
IB	0.0	13.4	0.0	0.0	0.0				
Scand.	-4.5	0.0	0.0	1.7	0.0				
Ost-E.	-3.4	0.0	-3.7	0.0	0.0				
UK	0.0	13.8	0.0	0.0	0.0				
I	0.0	2.4	3.7	0.0	0.0				

Table A9.3. Forecasts for European net imports under high gas demand (continued)

Net-power imports 2010 (net imports+, net exports-); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0.0	48.8	22.0	30.3	0.0	3.8	4.7	0.0	0.0
F	-48.8	0.0	-35.7	-24.2	-17.5	0.0	0.0	-13.7	-0.7
A / CH	-22.0	35.7	0.0	0.0	0.0	0.0	3.8	0.0	-1.8
Benelux	-30.3	24.2	0.0	0.0	0.0	-1.6	0.0	0.0	0.0
IB	0.0	17.5	0.0	0.0	0.0				
Scand.	-3.8	0.0	0.0	1.6	0.0				
Ost-E.	-4.7	0.0	-3.8	0.0	0.0				
UK	0.0	13.7	0.0	0.0	0.0				
I	0.0	0.7	1.8	0.0	0.0				

Net-power imports 2015 (net imports+, net exports-); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0.0	48.8	22.5	43.4	0.0	3.8	4.4	0.0	0.0
F	-48.8	0.0	-39.5	-14.3	-15.4	0.0	0.0	-13.6	-0.7
A / CH	-22.5	39.5	0.0	0.0	0.0	0.0	3.9	0.0	-1.8
Benelux	-43.4	14.3	0.0	0.0	0.0	-1.5	0.0	0.0	0.0
IB	0.0	15.4	0.0	0.0	0.0				
Scand.	-3.8	0.0	0.0	1.5	0.0				
Ost-E.	-4.4	0.0	-3.9	0.0	0.0				
UK	0.0	13.6	0.0	0.0	0.0				
I	0.0	0.7	1.8	0.0	0.0				

Net-power imports 2020 (net imports+, net exports-); TWh

Export	Import D	F	A / CH	Benelux	IB	Scand.	Ost-E.	UK	I
D	0.0	48.8	18.0	57.3	0.0	3.9	4.4	0.0	0.0
F	-48.8	0.0	-34.0	-2.2	-11.7	0.0	0.0	-13.6	-0.7
A / CH	-18.0	34.0	0.0	0.0	0.0	0.0	4.0	0.0	-1.8
Benelux	-57.3	2.2	0.0	0.0	0.0	-1.4	0.0	0.0	0.0
IB	0.0	11.7	0.0	0.0	0.0				
Scand.	-3.9	0.0	0.0	1.4	0.0				
Ost-E.	-4.4	0.0	-4.0	0.0	0.0				
UK	0.0	13.6	0.0	0.0	0.0				
I	0.0	0.7	1.8	0.0	0.0				

A10. Transmission capacities

Figure A10.1. Capacities of back-to-back stations between core and satellite regions in 1995 [MW]

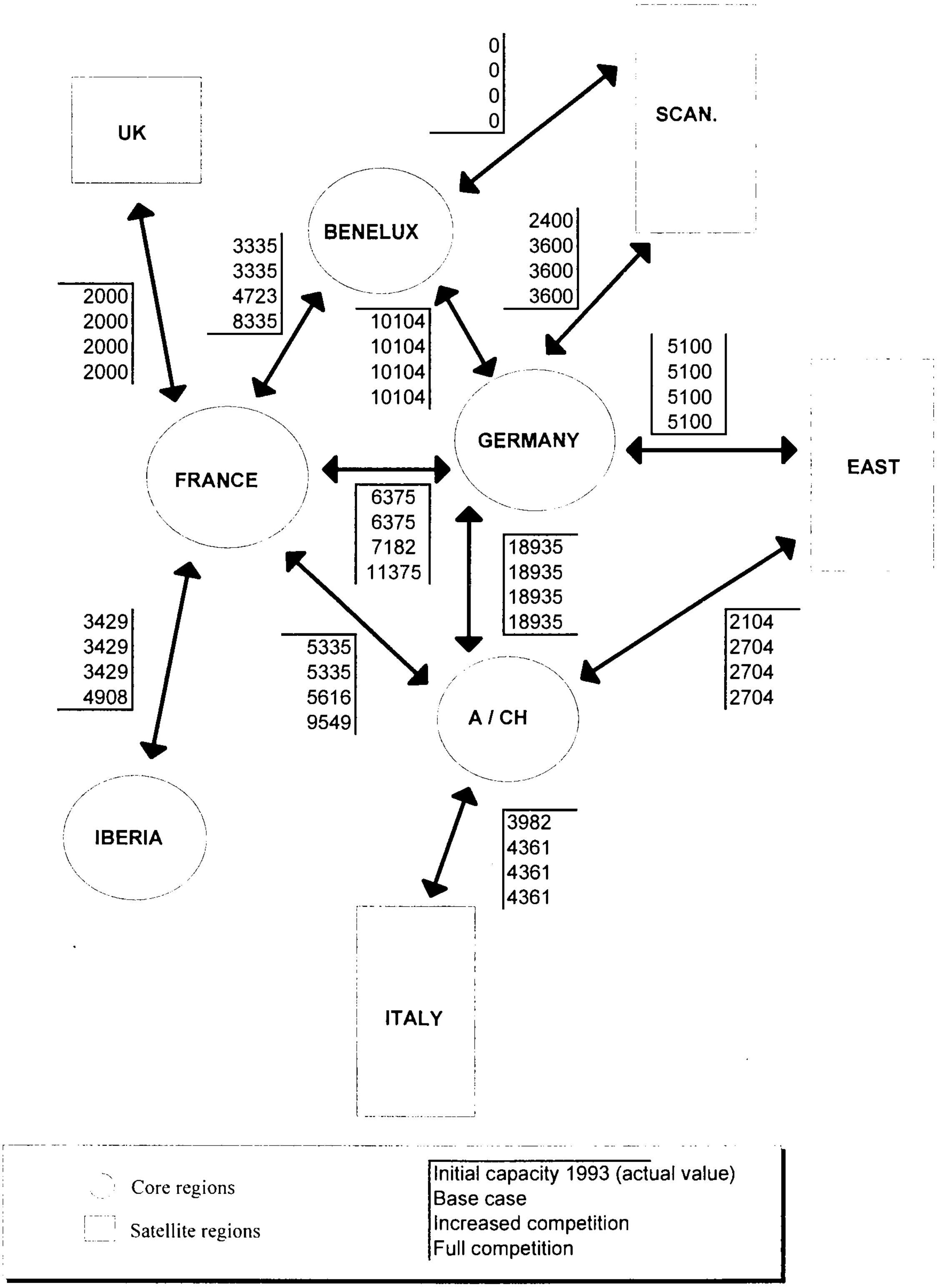


Figure A10.2. Capacities of back-to-back stations between core and satellite regions in 2000 [MW]

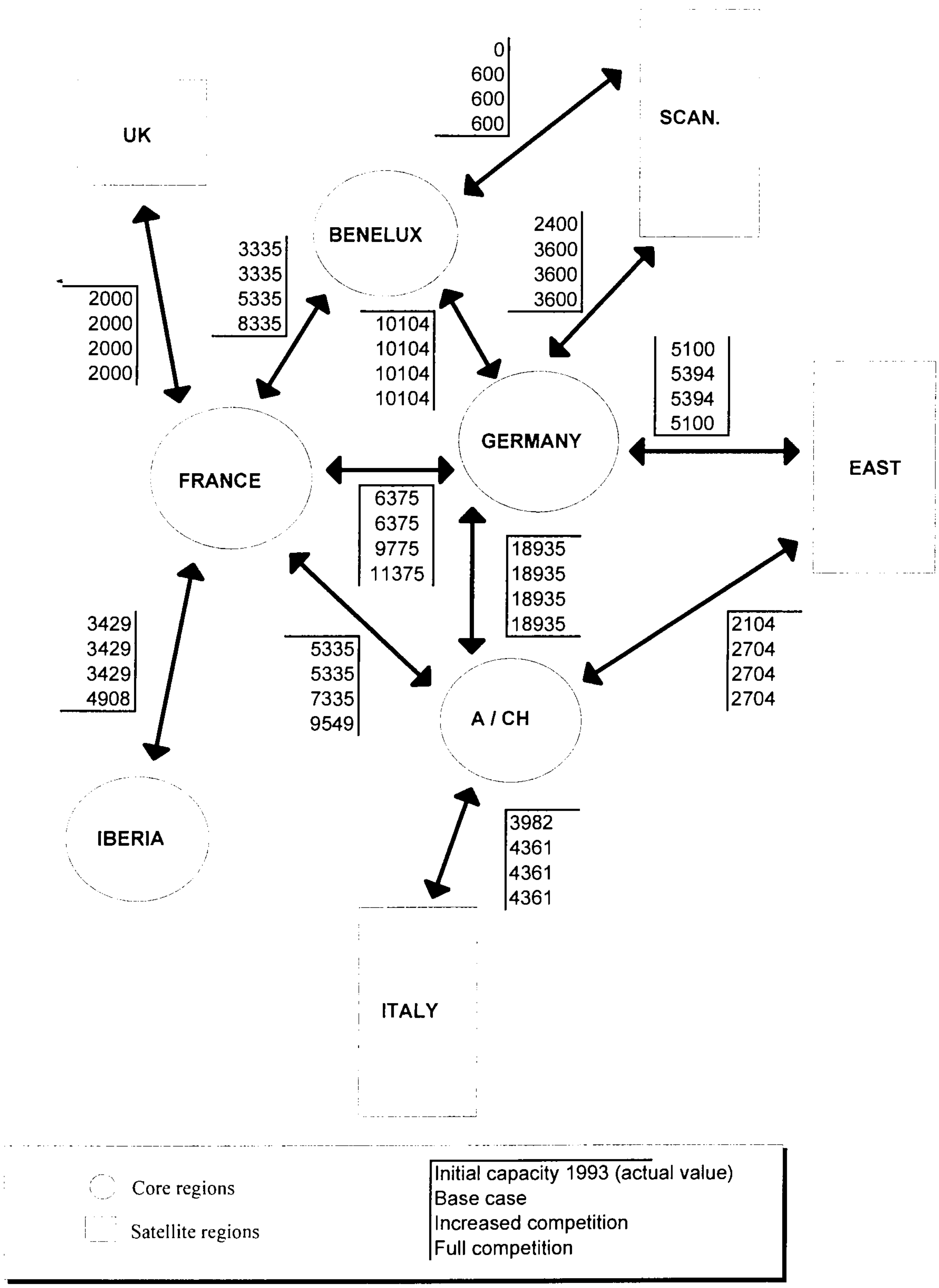


Figure A10.3. Capacities of back-to-back stations between core and satellite regions in 2010 [MW]

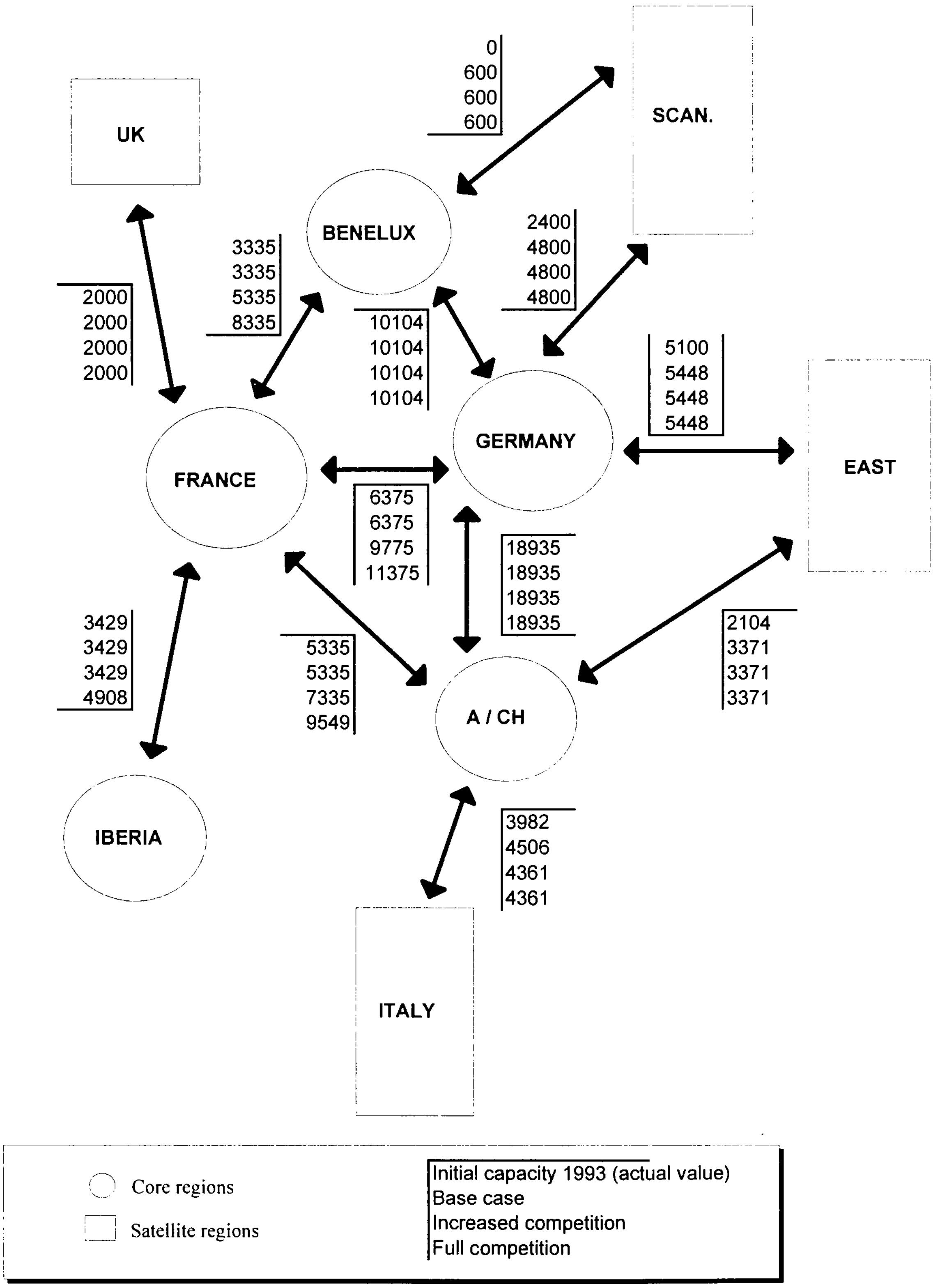
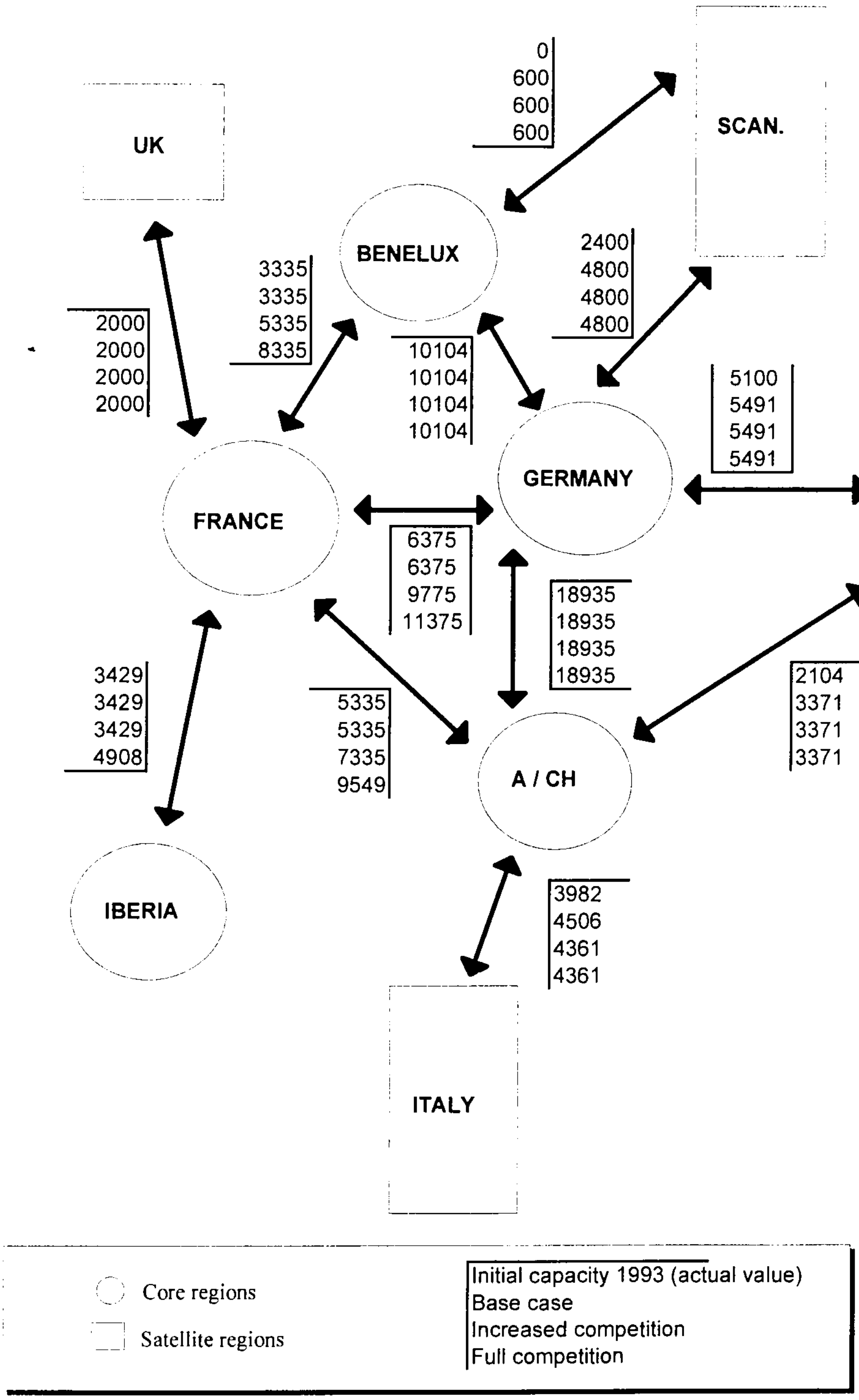


Figure A10.4. Capacities of back-to-back stations between core and satellite regions in 2020 [MW]



A11. Midas results

Table A11.1. Scenarios 2020: Germany, new conventional wisdom

	Summary electricity balance							Annual averages% change						% Change
	1992	1995	2000	2005	2010	2015	2020	92/95	95/00	00/05	05/10	10/15	15/20	1990/2020
Gross production (in GWh)														
Nuclear	**158775**	**159779**	**159779**	**156691**	**139178**	**98221**	**44653**	**0.21**	**0.00**	**-0.39**	**-2.34**	**-6.73**	**-14.59**	**-69.65**
Hard coal	137914	126950	186508	206275	225150	237698	247882	-2.72	8.00	2.04	1.77	1.09	0.84	78.08
Lignite	153152	114236	118016	109340	103791	100586	101765	-9.31	0.65	-1.52	-1.04	-0.63	0.23	23.24
Other solids	2835	2085	1888	1856	2082	1729	1494	-9.74	-1.96	-0.34	2.32	-3.65	-2.87	24.52
Total solids	**293901**	**243270**	**306413**	**317471**	**331023**	**340012**	**351141**	**-6.11**	**4.72**	**0.71**	**0.84**	**0.54**	**0.65**	**57.48**
Fuel oil	7817	17473	22660	22119	21167	11750	6534	30.75	5.34	-0.48	-0.88	-11.11	-11.07	-14.18
Diesel oil	3563	4312	7308	6235	4262	3528	3308	6.56	11.13	-3.13	-7.33	-3.71	-1.28	63.57
Other liquids	176	225	291	288	276	244	133	8.62	5.28	-0.24	-0.82	-2.45	-11.39	-91.34
Total liquids	**11556**	**22010**	**30259**	**28642**	**25705**	**15522**	**9975**	**23.96**	**6.57**	**-1.09**	**-2.14**	**-9.60**	**-8.46**	**-10.74**
Natural gas	32973	88257	79005	112662	156684	227243	289154	38.84	-2.19	7.36	6.82	7.72	4.94	704.64
Hydrogen	0	0	0	0	0	207	883		0.00	0.00	0.00	0.00	33.58	
Derived gases	8413	8751	7960	6817	5820	5466	4103	1.32	-1.88	-3.05	-3.11	-1.25	-5.57	-55.70
Total gas	**41387**	**97008**	**86966**	**119479**	**162504**	**232917**	**294140**	**32.84**	**-2.16**	**6.56**	**6.34**	**7.47**	**4.78**	**550.77**
Waste	**1042**	**1478**	**2677**	**2933**	**2946**	**2889**	**5150**	**12.36**	**12.61**	**1.84**	**0.09**	**-0.39**	**12.26**	**7.09**
Biomass	**4256**	**4187**	**10847**	**12424**	**14244**	**16134**	**30074**	**-0.55**	**20.97**	**2.75**	**2.77**	**2.52**	**13.26**	
Biofuels	**0**	**0**	**0**	**0**	**0**	**0**	**1**		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	
Total thermal	**352142**	**367953**	**437162**	**480949**	**536422**	**607474**	**690481**	**1.47**	**3.51**	**1.93**	**2.21**	**2.52**	**2.59**	**143.00**
Hydro	17265	17614	17786	18374	18670	18965	19261	0.67	0.19	0.65	0.32	0.31	0.31	21.28
Renewables/geothermal	88	348	812	1477	1851	2218	2585	58.41	18.44	12.71	4.62	3.68	3.11	9653.85
Total primary production	**17353**	**17963**	**18598**	**19851**	**20521**	**21183**	**21846**	**1.16**	**0.70**	**1.31**	**0.67**	**0.64**	**0.62**	**37.33**
Total without pumping	**528270**	**545695**	**615539**	**657491**	**696121**	**726878**	**756980**	**1.09**	**2.44**	**1.33**	**1.15**	**0.87**	**0.81**	**69.27**
Pumping	5200	4701	5421	5421	5421	5421	5421	-3.30	2.89	0.00	0.00	0.00	0.00	120.55
Fuel consumption (in ktoe)														
Nuclear	**39000**	**40111**	**41639**	**40835**	**36271**	**25597**	**11637**	**0.94**	**0.75**	**-0.39**	**-2.34**	**-6.73**	**-14.59**	**-67.82**
Hard coal	31949	29577	43480	45654	43896	45222	47618	-2.54	8.01	0.98	-0.78	0.60	1.04	50.53
Lignite	41099	29009	27471	25518	23801	22759	22949	-10.96	-1.08	-1.46	-1.38	-0.89	0.17	16.48
Other solids	657	486	440	411	406	329	287	-9.56	-1.95	-1.37	-0.24	-4.12	-2.69	5.26
Total solids	**73705**	**59072**	**71391**	**71583**	**68103**	**68310**	**70853**	**-7.11**	**3.86**	**0.05**	**-0.99**	**0.06**	**0.73**	**37.29**
Fuel oil	2686	5071	5168	5093	4939	2761	1581	23.60	0.38	-0.29	-0.61	-10.98	-10.55	-12.09
Diesel oil	1094	1210	1802	1542	1049	866	768	3.39	8.30	-3.07	-7.42	-3.76	-2.38	23.56
Other liquids	60	65	66	66	65	57	32	2.68	0.33	-0.05	-0.55	-2.32	-10.88	-91.13
Total liquids	**3841**	**6346**	**7037**	**6702**	**6052**	**3684**	**2381**	**18.22**	**2.09**	**-0.97**	**-2.02**	**-9.45**	**-8.36**	**-14.46**
Natural gas	7718	20699	17306	25075	32797	40546	48316	38.93	-3.52	7.70	5.52	4.33	3.57	470.90
Hydrogen	0	0	0	0	0	30	127		0.00	0.00	0.00	0.00	33.22	
Derived gases	1969	2052	1744	1517	1218	975	686	1.39	-3.21	-2.74	-4.29	-4.35	-6.81	-68.57
Total gas	**9688**	**22751**	**19049**	**26592**	**34015**	**41552**	**49128**	**32.92**	**-3.49**	**6.90**	**5.05**	**4.08**	**3.41**	**361.54**
Waste	**241**	**348**	**586**	**645**	**650**	**638**	**1010**	**13.14**	**10.96**	**1.95**	**0.15**	**-0.37**	**9.62**	**-6.53**
Biomass	**983**	**987**	**2374**	**2735**	**3144**	**3565**	**5899**	**0.14**	**19.19**	**2.87**	**2.83**	**2.54**	**10.60**	
Biofuels	**0**	**0**	**0**	**0**	**0**	**0**	**0**		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	

Table A11.2. Scenarios 2020: Germany, new conventional wisdom

	Demand and exchanges							Annual average % change						% Change
	1992	1995	2000	2005	2010	2015	2020	92/95	95/00	00/05	05/10	10/15	15/20	1992/2020
Demand (GWh)														
Industrial	210252	209071	235272	250172	262846	275433	290449	-0.19	2.39	1.24	0.99	0.94	1.07	1.16
Domestic	221588	245575	287610	309566	326817	333300	334311	3.49	3.21	1.48	1.09	0.39	0.06	1.48
Transports	14892	15787	17948	22094	26997	32994	39911	1.96	2.60	4.24	4.09	4.09	3.88	3.58
Total final demand	**446732**	**470434**	**540831**	**581832**	**616660**	**641728**	**664670**	**1.74**	**2.83**	**1.47**	**1.17**	**0.80**	**0.71**	**1.43**
Energy branch consumption	55985	54203	58708	60836	63041	67066	70142	-1.07	1.61	0.71	0.71	1.25	0.90	0.81
of which for hydrogen prod.	*0*	*0*	*0*	*0*	*0*	*47*	*80*						11.53	
Distribution losses	20106	21379	24674	26539	28127	29270	30317	2.07	2.91	1.47	1.17	0.80	0.71	1.48
Total demand	**522823**	**546016**	**624212**	**669207**	**707828**	**738064**	**765129**	**1.46**	**2.71**	**1.40**	**1.13**	**0.84**	**0.72**	**1.37**
Electricity exchanges (GWh)														
Imports	28285	32321	29674	29716	29707	27186	24149	4.55	-1.69	0.03	-0.01	-1.76	-2.34	-0.56
Exports	33732	32000	21000	18000	18000	16000	16000	-1.74	-8.08	-3.04	0.00	-2.33	0.00	-2.63
Net exports	**5447**	**-321**	**-8674**	**-11716**	**-11707**	**-11186**	**-8149**	**-138.93**	**93.29**	**6.20**	**-0.01**	**-0.91**	**-6.14**	
Electricity production (GWh)														
Conv. thermal power plants	352142	367953	437162	480949	536422	607474	690481	1.47	3.51	1.93	2.21	2.52	2.59	2.43
Nuclear power plants	158775	159779	159779	156691	139178	98221	44653	0.21	0.00	-0.39	-2.34	-6.73	-14.59	-4.43
Hydro and other renewables	17353	17963	18598	19851	20521	21183	21846	1.16	0.70	1.31	0.67	0.64	0.62	0.83
Total	**528270**	**545695**	**615539**	**657491**	**696121**	**726878**	**756980**	**1.09**	**2.44**	**1.33**	**1.15**	**0.87**	**0.81**	**1.29**
Load (GW)														
Total gross peak demand	81.28	85.26	95.96	102.38	108.12	111.93	115.29	1.61	2.39	1.30	1.10	0.69	0.59	1.26
System reserve margin	**1.53**	**1.47**	**1.39**	**1.32**	**1.34**	**1.27**	**1.27**	**-1.35**	**-1.11**	**-1.06**	**0.35**	**-1.09**	**-0.05**	**-0.68**
LOLP (in hours)	**4.03**	**4.28**	**4.37**	**4.30**	**4.34**	**3.77**	**4.30**	**2.07**	**0.42**	**-0.31**	**0.19**	**-2.79**	**2.63**	**0.23**

New heat from CHP (ktoe)														
Additional demand	0	0	0	1011.26078	1819.16625	2372.35956	2748.30114				12.46	5.45	2.99	
Potential production	0	0	165.845618	941.52545	1792.51669	2350.98576	7389.59127			41.52	13.74	5.57	25.74	

Table A11.3. Scenarios 2020: Germany, new conventional wisdom

	Electricity generating capacities (GW)							Capacity expansions (GW)						% change
	1992	1995	2000	2005	2010	2015	2020	93/95	96/00	2001/05	2006/10	2011/15	2016/20	1993/2020
Nuclear	**22.518**	**22.518**	**22.518**	**22.096**	**19.663**	**13.906**	**6.322**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
Monovalents														
Coal	17.575	18.139	24.729	28.079	26.236	23.418	21.167	0.943	7.085	3.600	0.000	0.000	0.000	11.628
Lignite	21.218	20.967	18.487	14.488	14.041	13.187	13.321	0.560	2.911	0.000	3.600	3.900	2.350	13.321
Residual fuel Oil	6.094	6.226	6.274	5.499	4.438	1.260	0.180	0.132	0.048	0.000	0.000	0.000	0.000	0.180
Natural gas conv.	8.466	9.553	10.135	9.925	9.415	4.764	1.965	1.087	0.582	0.000	0.000	0.000	0.000	1.669
Nat. Gas comb. cycle	0.000	0.387	0.687	0.687	5.187	19.337	28.012	0.387	0.300	0.000	4.500	14.150	8.675	28.012
Biomass	0.723	0.773	0.898	1.148	1.398	1.648	2.148	0.050	0.125	0.250	0.250	0.250	0.500	1.425
Total	**54.076**	**56.045**	**61.209**	**59.826**	**60.714**	**63.614**	**66.793**	**3.159**	**11.051**	**3.850**	**8.350**	**18.300**	**11.525**	**56.235**
Polyvalents														
With coal	9.478	9.478	10.178	8.793	6.211	3.638	1.981	0.000	0.700	0.000	0.000	0.000	0.000	0.700
Without coal	0.190	0.190	0.095	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Small autoproducers	14.400	13.154	11.344	8.846	9.026	9.206	9.252	0.055	0.000	0.000	2.250	2.250	2.250	6.805
Total	**24.068**	**22.822**	**21.617**	**17.639**	**15.237**	**12.844**	**11.233**	**0.055**	**0.700**	**0.000**	**2.250**	**2.250**	**2.250**	**7.505**
Peak Devices	**6.094**	**6.094**	**8.374**	**8.067**	**7.821**	**6.379**	**5.223**	**0.000**	**2.280**	**0.000**	**0.000**	**0.000**	**0.000**	**2.280**
New Technologies														
New coal	0.000	0.000	0.600	6.200	19.400	22.200	22.200	0.000	0.600	5.600	13.200	2.800	0.000	22.200
New CHP	0.000	0.000	1.500	3.800	4.750	6.000	14.600	0.000	1.500	2.300	0.950	1.250	8.600	14.600
Fuel cells	0.000	0.000	0.000	0.000	0.000	0.300	1.725	0.000	0.000	0.000	0.000	0.300	1.425	1.725
Biomass comb. cycle	0.000	0.000	0.900	0.900	0.900	0.900	2.525	0.000	0.900	0.000	0.000	0.000	1.625	2.525
Fuel oil comb. cycle	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	**0.000**	**0.000**	**3.000**	**10.900**	**25.050**	**29.400**	**41.050**	**0.000**	**3.000**	**7.900**	**14.150**	**4.350**	**11.650**	**41.050**
Total thermal	**106.756**	**107.478**	**116.718**	**118.528**	**128.485**	**126.143**	**130.621**	**3.214**	**17.031**	**11.750**	**24.750**	**24.900**	**25.425**	**107.070**
Hydro	3.005	3.043	3.068	3.194	3.244	3.294	3.344	0.038	0.025	0.126	0.050	0.050	0.050	0.339
Geothermal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Wind	0.215	0.550	0.800	1.050	1.300	1.550	1.800	0.335	0.250	0.250	0.250	0.250	0.250	1.585
Solar	0.000	0.000	0.010	0.035	0.060	0.085	0.110	0.000	0.010	0.025	0.025	0.025	0.025	0.110
Total without pumping	**109.976**	**111.071**	**120.596**	**122.807**	**133.089**	**131.072**	**135.875**	**3.587**	**17.316**	**12.151**	**25.075**	**25.225**	**25.750**	**109.104**
Pumping	6.924	6.924	7.984	7.984	7.984	7.984	7.984	0.000	1.060	0.000	0.000	0.000	0.000	1.060
Total	**116.900**	**117.995**	**128.580**	**130.791**	**141.073**	**139.056**	**143.859**	**3.587**	**18.376**	**12.151**	**25.075**	**25.225**	**25.750**	**110.164**

Table A11.4. Scenarios 2020: Germany, negotiated TPA

	Summary electricity balance							Annual average % change						% Change
	1992	1995	2000	2005	2010	2015	2020	92/95	95/00	00/05	05/10	10/15	15/20	1990/2020
Gross production (in GWh)														
Nuclear	**158775**	**159779**	**159779**	**156691**	**139178**	**98221**	**44653**	**0.21**	**0.00**	**-0.39**	**-2.34**	**-6.73**	**-14.59**	**-69.65**
Hard coal	137914	117098	145591	165872	196999	219343	234859	-5.31	4.45	2.64	3.50	2.17	1.38	68.73
Lignite	153152	114236	118016	109340	103791	100586	101765	-9.31	0.65	-1.52	-1.04	-0.63	0.23	23.24
Other solids	2835	2079	1867	1847	2093	1886	1592	-9.82	-2.13	-0.22	2.53	-2.06	-3.33	32.70
Total solids	**293901**	**233413**	**265475**	**277059**	**302884**	**321815**	**338217**	**-7.39**	**2.61**	**0.86**	**1.80**	**1.22**	**1.00**	**51.69**
Fuel oil	7817	18918	22000	23332	21255	10581	12300	34.26	3.06	1.18	-1.85	-13.02	3.06	61.57
Diesel oil	3563	4080	7175	6625	2642	1918	1911	4.62	11.95	-1.58	-16.80	-6.20	-0.08	-5.51
Other liquids	176	226	291	289	281	220	251	8.79	5.16	-0.13	-0.56	-4.82	2.69	-83.70
Total liquids	**11556**	**23225**	**29466**	**30246**	**24178**	**12719**	**14462**	**26.20**	**4.88**	**0.52**	**-4.38**	**-12.06**	**2.60**	**29.41**
Natural gas	32973	80423	78980	113131	150499	219249	282792	34.61	-0.36	7.45	5.87	7.82	5.22	686.94
Hydrogen	0	0	0	0	0	123	1276		0.00	0.00	0.00	0.00	59.64	
Derived gases	8413	8649	7909	6813	5633	5002	4046	0.93	-1.77	-2.94	-3.73	-2.35	-4.15	-56.32
Total gas	**41387**	**89072**	**86889**	**119945**	**156132**	**224374**	**288114**	**29.11**	**-0.50**	**6.66**	**5.41**	**7.52**	**5.13**	**537.44**
Waste	**1042**	**1478**	**2213**	**2586**	**2626**	**2628**	**4782**	**12.35**	**8.41**	**3.17**	**0.30**	**0.01**	**12.72**	**-0.57**
Biomass	**4256**	**4187**	**8997**	**10842**	**12636**	**14467**	**27550**	**-0.54**	**16.53**	**3.80**	**3.11**	**2.74**	**13.75**	
Biofuels	**0**	**0**	**0**	**0**	**0**	**0**	**0**		**0.00**	**0.00**	**4.26**	**3.79**	**19.34**	
Total thermal	**352142**	**351375**	**393040**	**440679**	**498455**	**576002**	**673125**	**-0.07**	**2.27**	**2.31**	**2.49**	**2.93**	**3.17**	**136.89**
Hydro	17265	17614	17786	18374	18670	18965	19261	0.67	0.19	0.65	0.32	0.31	0.31	21.28
Renewables/geothermal	88	348	812	1477	1851	2218	2585	58.41	18.44	12.71	4.62	3.68	3.11	9653.85
Total primary production	**17353**	**17963**	**18598**	**19851**	**20521**	**21183**	**21846**	**1.16**	**0.70**	**1.31**	**0.67**	**0.64**	**0.62**	**37.33**
Total without pumping	**528270**	**529116**	**571417**	**617221**	**658154**	**695406**	**739624**	**0.05**	**1.55**	**1.55**	**1.29**	**1.11**	**1.24**	**65.39**
Pumping	5200	4701	5421	5421	5421	5421	5421	-3.30	2.89	0.00	0.00	0.00	0.00	120.55
Fuel consumption (in ktoe)														
Nuclear	**39000**	**40111**	**41639**	**40835**	**36271**	**25597**	**11637**	**0.94**	**0.75**	**-0.39**	**-2.34**	**-6.73**	**-14.59**	**-67.82**
Hard coal	31949	27292	34005	36558	37447	41111	44171	-5.12	4.50	1.46	0.48	1.88	1.45	39.64
Lignite	41099	29009	27471	25518	23801	22759	22949	-10.96	-1.08	-1.46	-1.38	-0.89	0.17	16.48
Other solids	657	485	436	407	398	354	299	-9.64	-2.09	-1.37	-0.46	-2.34	-3.27	9.83
Total solids	**73705**	**56785**	**61912**	**62483**	**61647**	**64224**	**67419**	**-8.33**	**1.74**	**0.18**	**-0.27**	**0.82**	**0.98**	**30.64**
Fuel oil	2686	5490	5018	5373	4936	2482	2447	26.91	-1.78	1.38	-1.68	-12.85	-0.28	36.10
Diesel oil	1094	1142	1769	1632	657	457	444	1.44	9.14	-1.60	-16.62	-7.00	-0.57	-28.45
Other liquids	60	66	66	67	65	52	50	2.84	0.22	0.06	-0.39	-4.62	-0.64	-86.27
Total liquids	**3841**	**6698**	**6853**	**7071**	**5659**	**2991**	**2942**	**20.37**	**0.46**	**0.63**	**-4.36**	**-11.97**	**-0.33**	**5.70**
Natural gas	7718	18904	17300	25140	32775	40568	48320	34.80	-1.76	7.76	5.45	4.36	3.56	470.95
Hydrogen	0	0	0	0	0	18	184		0.00	0.00	0.00	0.00	59.24	
Derived gases	1969	2033	1732	1514	1227	925	691	1.07	-3.15	-2.66	-4.12	-5.48	-5.67	-68.31
Total gas	**9688**	**20937**	**19032**	**26654**	**34002**	**41511**	**49195**	**29.29**	**-1.89**	**6.97**	**4.99**	**4.07**	**3.45**	**362.16**
Waste	**241**	**348**	**496**	**578**	**588**	**588**	**944**	**13.13**	**7.33**	**3.11**	**0.33**	**0.01**	**9.93**	**-12.63**
Biomass	**983**	**987**	**2017**	**2424**	**2829**	**3238**	**5440**	**0.15**	**15.37**	**3.75**	**3.14**	**2.73**	**10.94**	
Biofuels	**0**	**0**	**0**	**0**	**0**	**0**	**0**		**0.00**	**0.00**	**4.26**	**3.79**	**16.51**	

Table A11.5. Scenarios 2020: Germany, negotiated TPA

	Electricity generating capacities (GW)							Capacity expansions (GW)						% change
	1992	1995	2000	2005	2010	2015	2020	93/95	96/00	2001/05	2006/10	2011/15	2016/20	1993/2020
Nuclear	**22.518**	**22.518**	**22.518**	**22.096**	**19.663**	**13.906**	**6.322**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
Monovalents														
Coal	17.575	18.139	24.729	24.479	22.636	19.818	17.567	0.943	7.085	0.000	0.000	0.000	0.000	8.028
Lignite	21.218	20.967	18.487	14.488	14.041	13.187	13.321	0.560	2.911	0.000	3.600	3.900	2.350	13.321
Residual fuel oil	6.094	6.226	6.274	5.499	4.438	1.260	0.180	0.132	0.048	0.000	0.000	0.000	0.000	0.180
Natural gas conv.	8.466	9.553	10.135	9.925	9.415	4.764	1.965	1.087	0.582	0.000	0.000	0.000	0.000	1.669
Nat. gas comb. cycle	0.000	0.387	0.687	0.687	2.937	16.387	26.387	0.387	0.300	0.000	2.250	13.450	10.000	26.387
Biomass	0.723	0.773	0.898	1.148	1.398	1.648	2.148	0.050	0.125	0.250	0.250	0.250	0.500	1.425
Total	**54.076**	**56.045**	**61.209**	**56.226**	**54.864**	**57.064**	**61.568**	**3.159**	**11.051**	**0.250**	**6.100**	**17.600**	**12.850**	**51.010**
Polyvalents														
With coal	9.478	9.478	10.178	8.793	6.211	3.638	1.981	0.000	0.700	0.000	0.000	0.000	0.000	0.700
Without coal	0.190	0.190	0.095	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Small autoproducers	14.400	13.154	11.344	9.746	9.026	9.206	9.252	0.055	0.000	0.900	1.350	2.250	2.250	6.805
Total	**24.068**	**22.822**	**21.617**	**18.539**	**15.237**	**12.844**	**11.233**	**0.055**	**0.700**	**0.900**	**1.350**	**2.250**	**2.250**	**7.505**
Peak devices	**6.094**	**6.094**	**7.234**	**6.927**	**6.681**	**5.239**	**4.083**	**0.000**	**1.140**	**0.000**	**0.000**	**0.000**	**0.000**	**1.140**
New technologies														
New coal	0.000	0.000	0.600	6.400	19.400	22.000	22.800	0.000	0.600	5.800	13.000	2.600	0.800	22.800
New CHP	0.000	0.000	0.000	4.176	4.376	6.476	13.876	0.000	0.000	4.176	0.200	2.100	7.400	13.876
Fuel cells	0.000	0.000	0.000	0.075	0.075	0.225	1.200	0.000	0.000	0.075	0.000	0.150	0.975	1.200
Biomass comb. cycle	0.000	0.000	0.600	0.650	0.650	0.650	2.150	0.000	0.600	0.050	0.000	0.000	1.500	2.150
Fuel oil comb. cycle	0.000	0.000	0.000	0.000	0.000	0.000	1.200	0.000	0.000	0.000	0.000	0.000	1.200	1.200
Total	**0.000**	**0.000**	**1.200**	**11.301**	**24.501**	**29.351**	**41.226**	**0.000**	**1.200**	**10.101**	**13.200**	**4.850**	**11.875**	**41.226**
Total thermal	**106.756**	**107.478**	**113.778**	**115.089**	**120.946**	**118.404**	**124.432**	**3.214**	**14.091**	**11.251**	**20.650**	**24.700**	**26.975**	**100.881**
Hydro	3.005	3.043	3.068	3.194	3.244	3.294	3.344	0.038	0.025	0.126	0.050	0.050	0.050	0.339
Geothermal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Wind	0.215	0.550	0.800	1.050	1.300	1.550	1.800	0.335	0.250	0.250	0.250	0.250	0.250	1.585
Solar	0.000	0.000	0.010	0.035	0.060	0.085	0.110	0.000	0.010	0.025	0.025	0.025	0.025	0.110
Total without pumping	**109.976**	**111.071**	**117.656**	**119.368**	**125.550**	**123.333**	**129.686**	**3.587**	**14.376**	**11.652**	**20.975**	**25.025**	**27.300**	**102.915**
Pumping	6.924	6.924	7.984	7.984	7.984	7.984	7.984	0.000	1.060	0.000	0.000	0.000	0.000	1.060
Total	**116.900**	**117.995**	**125.640**	**127.352**	**133.534**	**131.317**	**137.670**	**3.587**	**15.436**	**11.652**	**20.975**	**25.025**	**27.300**	**103.975**

Table A11.6. Scenarios 2020: Germany, negotiated TPA

	Demand and exchanges							Annual average % change						% change
	1992	1995	2000	2005	2010	2015	2020	92/95	95/00	00/05	05/10	10/15	15/20	1992/2020
Demand (GWh)														
Industrial	210252	209090	235920	250680	261987	275392	290440	-0.18	2.44	1.22	0.89	1.00	1.07	1.16
Domestic	221588	245554	288787	310047	326629	333495	333387	3.48	3.30	1.43	1.05	0.42	-0.01	1.47
Transports	14892	15789	17951	22095	26999	33024	39906	1.97	2.60	4.24	4.09	4.11	3.86	3.58
Total final demand	**446732**	**470432**	**542659**	**582822**	**615615**	**641912**	**663732**	**1.74**	**2.90**	**1.44**	**1.10**	**0.84**	**0.67**	**1.42**
Energy branch consumption	55985	53199	55784	58205	60620	64818	69085	-1.69	0.95	0.85	0.82	1.35	1.28	0.75
of which for hydrogen prod.	*0*	*0*	*0*	*0*	*0*	*47*	*85*						12.86	
Distribution losses	20106	21379	24758	26584	28079	29279	30274	2.07	2.98	1.43	1.10	0.84	0.67	1.47
Total demand	**522823**	**545010**	**623200**	**667610**	**704314**	**736009**	**763091**	**1.39**	**2.72**	**1.39**	**1.08**	**0.88**	**0.73**	**1.36**
Electricity exchanges (GWh)														
Imports	28285	38537	70535	66888	65512	63261	50691	10.86	12.85	-1.06	-0.41	-0.70	-4.33	2.11
Exports	33732	22643	18751	16498	19352	22658	27224	-12.44	-3.70	-2.53	3.24	3.20	3.74	-0.76
Net exports	**5447**	**-15894**	**-51784**	**-50390**	**-46160**	**-40603**	**-23467**	**-242.90**	**26.65**	**-0.54**	**-1.74**	**-2.53**	**-10.39**	
Electricity production (GWh)														
Conv. thermal power plants	352142	351375	393040	440679	498455	576002	673125	-0.07	2.27	2.31	2.49	2.93	3.17	2.34
Nuclear power plants	158775	159779	159779	156691	139178	98221	44653	0.21	0.00	-0.39	-2.34	-6.73	-14.59	-4.43
Hydro and other renewables	17353	17963	18598	19851	20521	21183	21846	1.16	0.70	1.31	0.67	0.64	0.62	0.83
Total	**528270**	**529116**	**571417**	**617221**	**658154**	**695406**	**739624**	**0.05**	**1.55**	**1.55**	**1.29**	**1.11**	**1.24**	**1.21**
Load (GW)														
Total gross peak demand	81.28	83.86	95.75	102.21	108.14	112.94	116.92	1.05	2.69	1.32	1.13	0.87	0.70	1.31
System reserve margin	**1.53**	**1.47**	**1.36**	**1.28**	**1.27**	**1.20**	**1.21**	**-1.30**	**-1.58**	**-1.11**	**-0.17**	**-1.18**	**0.22**	**-0.82**
LOLP (in hours)	**4.03**	**5.98**	**11.50**	**24.91**	**24.70**	**26.23**	**24.04**	**14.13**	**13.96**	**16.72**	**-0.17**	**1.21**	**-1.73**	**6.59**

New heat from CHP (ktoe)														
Additional demand	0	0	0	1024.1914	1710.59525	2484.66062	2984.29042				10.80	7.75	3.73	
Potential production	0	0	110.563745	960.338036	1508.17187	3336.13266	6644.05391			54.09	9.45	17.21	14.77	

Table A11.7. Scenarios 2020: Germany, TPA

	Summary electricity balance							Annual average % change						% change
	1992	1995	2000	2005	2010	2015	2020	92/95	95/00	00/05	05/10	10/15	15/20	1990/2020
Gross production (in GWh)														
Nuclear	**158775**	**159779**	**159779**	**156691**	**139178**	**98221**	**44653**	**0.21**	**0.00**	**-0.39**	**-2.34**	**-6.73**	**-14.59**	**-69.65**
Hard coal	137914	109936	102273	140968	177718	207981	231116	-7.28	-1.43	6.63	4.74	3.19	2.13	66.04
Lignite	153152	114236	118016	109340	103791	100586	101765	-9.31	0.65	-1.52	-1.04	-0.63	0.23	23.24
Other solids	2835	2073	1794	1827	2076	1969	1650	-9.90	-2.85	0.36	2.60	-1.06	-3.47	37.49
Total solids	**293901**	**226246**	**222084**	**252135**	**283586**	**310535**	**334531**	**-8.35**	**-0.37**	**2.57**	**2.38**	**1.83**	**1.50**	**50.03**
Fuel oil	7817	18343	22928	22477	21265	10718	12141	32.88	4.56	-0.40	-1.10	-12.80	2.52	59.47
Diesel oil	3563	4033	6953	6548	2503	2062	2263	4.22	11.51	-1.19	-17.50	-3.80	1.87	11.88
Other liquids	176	226	291	289	283	223	185	8.65	5.25	-0.13	-0.47	-4.65	-3.69	-88.02
Total liquids	**11556**	**22602**	**30173**	**29314**	**24050**	**13004**	**14588**	**25.06**	**5.95**	**-0.58**	**-3.88**	**-11.57**	**2.33**	**30.54**
Natural gas	32973	75596	80462	112511	145515	207205	278701	31.86	1.26	6.94	5.28	7.32	6.11	675.55
Hydrogen	0	0	0	0	0	82	841		0.00	0.00	0.00	0.00	59.27	
Derived gases	8413	8583	7884	6791	5481	4758	4027	0.67	-1.68	-2.94	-4.19	-2.79	-3.28	-56.52
Total gas	**41387**	**84179**	**88346**	**119302**	**150996**	**212045**	**283569**	**26.70**	**0.97**	**6.19**	**4.82**	**7.03**	**5.99**	**527.38**
Waste	**1042**	**1478**	**1747**	**2155**	**2238**	**2294**	**4470**	**12.34**	**3.40**	**4.30**	**0.75**	**0.50**	**14.27**	**-7.04**
Biomass	**4256**	**4187**	**7149**	**8959**	**10710**	**12486**	**25547**	**-0.54**	**11.29**	**4.62**	**3.63**	**3.12**	**15.39**	
Biofuels	**0**	**0**	**0**	**0**	**0**	**0**	**0**		**0.00**	**0.00**	**4.36**	**3.79**	**3.39**	
Total thermal	**352142**	**338691**	**349498**	**411866**	**471579**	**550364**	**662705**	**-1.29**	**0.63**	**3.34**	**2.74**	**3.14**	**3.78**	**133.22**
Hydro	17265	17614	17786	18374	18670	18965	19261	0.67	0.19	0.65	0.32	0.31	0.31	21.28
Renewables/geothermal	88	348	812	1477	1851	2218	2585	58.41	18.44	12.71	4.62	3.68	3.11	9653.85
Total primary production	**17353**	**17963**	**18598**	**19851**	**20521**	**21183**	**21846**	**1.16**	**0.70**	**1.31**	**0.67**	**0.64**	**0.62**	**37.33**
Total without pumping	**528270**	**516433**	**527875**	**588408**	**631278**	**669768**	**729204**	**-0.75**	**0.44**	**2.19**	**1.42**	**1.19**	**1.71**	**63.06**
Pumping	5200	4701	5421	5421	5421	5421	5421	-3.30	2.89	0.00	0.00	0.00	0.00	120.55
Fuel consumption (in Ktoe)														
Nuclear	**39000**	**40111**	**41639**	**40835**	**36271**	**25597**	**11637**	**0.94**	**0.75**	**-0.39**	**-2.34**	**-6.73**	**-14.59**	**-67.82**
Hard coal	31949	25630	24089	31170	33427	38930	43254	-7.08	-1.23	5.29	1.41	3.10	2.13	36.74
Lignite	41099	29009	27471	25518	23801	22759	22949	-10.96	-1.08	-1.46	-1.38	-0.89	0.17	16.48
Other solids	657	483	423	404	391	369	309	-9.71	-2.65	-0.90	-0.67	-1.15	-3.48	13.23
Total solids	**73705**	**55122**	**51983**	**57092**	**57619**	**62058**	**66511**	**-9.23**	**-1.17**	**1.89**	**0.18**	**1.50**	**1.40**	**28.88**
Fuel oil	2686	5324	5235	5177	4943	2516	2404	25.62	-0.34	-0.22	-0.92	-12.63	-0.91	33.67
Diesel oil	1094	1129	1713	1610	618	491	525	1.05	8.69	-1.23	-17.44	-4.51	1.37	-15.50
Other liquids	60	65	66	67	66	52	37	2.71	0.32	0.05	-0.29	-4.46	-6.92	-89.95
Total liquids	**3841**	**6519**	**7014**	**6854**	**5627**	**3059**	**2965**	**19.29**	**1.48**	**-0.46**	**-3.87**	**-11.47**	**-0.62**	**6.54**
Natural gas	7718	17801	17633	24996	32774	38923	48320	32.12	-0.19	7.23	5.57	3.50	4.42	470.95
Hydrogen	0	0	0	0	0	12	121		0.00	0.00	0.00	0.00	58.90	
Derived gases	1969	2021	1728	1509	1234	894	698	0.87	-3.09	-2.67	-3.93	-6.25	-4.82	-67.99
Total gas	**9688**	**19822**	**19361**	**26505**	**34009**	**39829**	**49139**	**26.95**	**-0.47**	**6.48**	**5.11**	**3.21**	**4.29**	**361.64**
Waste	**241**	**348**	**405**	**495**	**512**	**524**	**884**	**13.12**	**3.05**	**4.10**	**0.71**	**0.43**	**11.03**	**-18.25**
Biomass	**983**	**987**	**1656**	**2056**	**2453**	**2850**	**5049**	**0.15**	**10.91**	**4.42**	**3.59**	**3.05**	**12.12**	
Biofuels	**0**	**0**	**0**	**0**	**0**	**0**	**0**		**0.00**	**0.00**	**4.36**	**3.79**	**3.39**	

Table A11.8. Scenarios 2020: Germany,TPA

	Demand and exchanges							Annual average % change						%Change
	1992	1995	2000	2005	2010	2015	2020	92/95	95/00	00/05	05/10	10/15	15/20	1992/2020
Demand (GWh)														
Industrial	210252	209101	236390	250894	261076	275162	289591	-0.18	2.48	1.20	0.80	1.06	1.03	1.15
Domestic	221588	245558	289294	309899	326413	331980	331911	3.48	3.33	1.39	1.04	0.34	0.00	1.45
Transports	14892	15790	17966	22088	27002	33007	39896	1.97	2.62	4.22	4.10	4.10	3.86	3.58
Total final demand	**446732**	**470449**	**543650**	**582882**	**614491**	**640149**	**661398**	**1.74**	**2.93**	**1.40**	**1.06**	**0.82**	**0.66**	**1.41**
Energy branch consumption	55985	52296	52560	56301	58924	63179	68527	-2.25	0.10	1.38	0.91	1.40	1.64	0.72
of which for hydrogen prod.	*0*	*0*	*0*	*0*	*0*	*46*	*80*						11.71	
Distribution losses	20106	21380	24803	26586	28028	29198	30168	2.07	3.02	1.40	1.06	0.82	0.66	1.46
Total demand	**522823**	**544125**	**621013**	**665769**	**701443**	**732527**	**760093**	**1.34**	**2.68**	**1.40**	**1.05**	**0.87**	**0.74**	**1.35**
Electricity exchanges (GWh)														
Imports	28285	49307	108291	92815	87815	82293	56867	20.35	17.04	-3.04	-1.10	-1.29	-7.12	2.53
Exports	33732	21615	15153	15454	17650	19534	25978	-13.79	-6.86	0.39	2.69	2.05	5.87	-0.93
Net exports	**5447**	**-27692**	**-93138**	**-77361**	**-70165**	**-62759**	**-30889**	**-271.95**	**27.45**	**-3.64**	**-1.93**	**-2.21**	**-13.22**	
Electricity production (GWh)														
Conv. thermal power plants	352142	338691	349498	411866	471579	550364	662705	-1.29	0.63	3.34	2.74	3.14	3.78	2.28
Nuclear power plants	158775	159779	159779	156691	139178	98221	44653	0.21	0.00	-0.39	-2.34	-6.73	-14.59	-4.43
Hydro and other renewables	17353	17963	18598	19851	20521	21183	21846	1.16	0.70	1.31	0.67	0.64	0.62	0.83
Total	**528270**	**516433**	**527875**	**588408**	**631278**	**669768**	**729204**	**-0.75**	**0.44**	**2.19**	**1.42**	**1.19**	**1.71**	**1.16**
Load (GW)														
Total gross peak demand	81.28	83.62	95.04	101.85	107.54	111.98	116.29	0.95	2.59	1.39	1.09	0.81	0.76	1.29
System reserve margin	**1.53**	**1.47**	**1.35**	**1.27**	**1.25**	**1.17**	**1.20**	**-1.26**	**-1.75**	**-1.20**	**-0.30**	**-1.24**	**0.39**	**-0.87**
LOLP (in hours)	**4.03**	**7.11**	**17.73**	**24.59**	**24.77**	**40.61**	**24.99**	**20.90**	**20.04**	**6.76**	**0.14**	**10.40**	**-9.26**	**6.74**

New heat from CHP (ktoe)														
Additional demand	0	0	0	1017.68536	1618.32728	2593.56115	2974.85159				9.72	9.89	2.78	
Potential production	0	0	55.2818726	936.523992	1565.7626	2915.6849	7117.26926			76.11	10.83	13.24	19.54	

Table A11.9. Scenarios 2020: Germany, TPA

	Electricity generating capacities (GW)							Capacity expansions (GW)						% change
	1992	1995	2000	2005	2010	2015	2020	93/95	96/00	2001/05	2006/10	2011/15	2016/20	1993/2020
Nuclear	**22.518**	**22.518**	**22.518**	**22.096**	**19.663**	**13.906**	**6.322**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
Monovalents														
Coal	17.575	18.139	24.729	24.479	22.636	19.818	17.567	0.943	7.085	0.000	0.000	0.000	0.000	8.028
Lignite	21.218	20.967	18.487	14.488	14.041	13.187	13.321	0.560	2.911	0.000	3.600	3.900	2.350	13.321
Residual fuel Oil	6.094	6.226	6.274	5.499	4.438	1.260	0.180	0.132	0.048	0.000	0.000	0.000	0.000	0.180
Natural gas conv.	8.466	9.553	10.135	9.925	9.415	4.764	1.965	1.087	0.582	0.000	0.000	0.000	0.000	1.669
Nat. gas comb. cycle	0.000	0.387	0.687	0.687	1.137	14.612	24.912	0.387	0.300	0.000	0.450	13.475	10.300	24.912
Biomass	0.723	0.773	0.898	1.148	1.398	1.648	2.148	0.050	0.125	0.250	0.250	0.250	0.500	1.425
Total	**54.076**	**56.045**	**61.209**	**56.226**	**53.064**	**55.289**	**60.093**	**3.159**	**11.051**	**0.250**	**4.300**	**17.625**	**13.150**	**49.535**
Polyvalents														
With coal	9.478	9.478	10.178	8.793	6.211	3.638	1.981	0.000	0.700	0.000	0.000	0.000	0.000	0.700
Without coal	0.190	0.190	0.095	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Small autoproducers	14.400	13.154	11.344	9.746	9.926	10.106	10.152	0.055	0.000	0.900	2.250	2.250	2.250	7.705
Total	**24.068**	**22.822**	**21.617**	**18.539**	**16.137**	**13.744**	**12.133**	**0.055**	**0.700**	**0.900**	**2.250**	**2.250**	**2.250**	**8.405**
Peak devices	**6.094**	**6.094**	**6.544**	**6.237**	**5.991**	**4.549**	**3.393**	**0.000**	**0.450**	**0.000**	**0.000**	**0.000**	**0.000**	**0.450**
New technologies														
New coal	0.000	0.000	0.400	5.600	18.200	20.800	22.400	0.000	0.400	5.200	12.600	2.600	1.600	22.400
New CHP	0.000	0.000	0.000	4.219	4.619	6.169	13.569	0.000	0.000	4.219	0.400	1.550	7.400	13.569
Fuel cells	0.000	0.000	0.000	0.075	0.075	0.225	1.125	0.000	0.000	0.075	0.000	0.150	0.900	1.125
Biomass comb. cycle	0.000	0.000	0.300	0.350	0.350	0.350	1.850	0.000	0.300	0.050	0.000	0.000	1.500	1.850
Fuel oil comb. cycle	0.000	0.000	0.000	0.000	0.000	0.000	1.200	0.000	0.000	0.000	0.000	0.000	1.200	1.200
Total	**0.000**	**0.000**	**0.700**	**10.244**	**23.244**	**27.544**	**40.144**	**0.000**	**0.700**	**9.544**	**13.000**	**4.300**	**12.600**	**40.144**
Total thermal	**106.756**	**107.478**	**112.588**	**113.342**	**118.099**	**115.032**	**122.085**	**3.214**	**12.901**	**10.694**	**19.550**	**24.175**	**28.000**	**98.534**
Hydro	3.005	3.043	3.068	3.194	3.244	3.294	3.344	0.038	0.025	0.126	0.050	0.050	0.050	0.339
Geothermal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Wind	0.215	0.550	0.800	1.050	1.300	1.550	1.800	0.335	0.250	0.250	0.250	0.250	0.250	1.585
Solar	0.000	0.000	0.010	0.035	0.060	0.085	0.110	0.000	0.010	0.025	0.025	0.025	0.025	0.110
Total without pumping	**109.976**	**111.071**	**116.466**	**117.621**	**122.703**	**119.961**	**127.339**	**3.587**	**13.186**	**11.095**	**19.875**	**24.500**	**28.325**	**100.568**
Pumping	6.924	6.924	7.984	7.984	7.984	7.984	7.984	0.000	1.060	0.000	0.000	0.000	0.000	1.060
Total	**116.900**	**117.995**	**124.450**	**125.605**	**130.687**	**127.945**	**135.323**	**3.587**	**14.246**	**11.095**	**19.875**	**24.500**	**28.325**	**101.628**

APPENDIX B

Gas

B1. Survey of the literature

B1.1. The European gas industry

This chapter reviews selected papers relating to the European gas industry:

Golombek, R., Gjelsvik, E. and Rosendahl, K.E. [1995] 'Effects of Liberalizing the Natural Gas Markets in Western Europe'. *The Energy Journal*, Vol. 16, No 1.

This paper models gas supply to Europe assuming that the major producers (Algeria, Netherlands, Norway, Russia, UK) are profit maximizing Cournot oligopolists able to sell to all markets under a TPA regime to large consumers and distribution companies. A static equilibrium approach is adopted. The paper identifies gains in economic welfare of 15–20% arising from trade and the removal of price discrimination.

Gains from trade are described, with and without the interconnector between continental Europe and the UK. Without the interconnector imports from Norway replace much of UK production. Algerian production approximately doubles, and total market volumes increase by some 10% as prices fall (elasticities are assumed to be close to 1). With the interconnector between the UK and continental Europe, Algeria's production increases further, as does production from the CIS and the Netherlands. Production from Norway and the UK declines (Norwegian exports to the UK are displaced). Total production increases by just under 10%.

In both cases, there are large gains due to production shifting to lower cost sources. The presumption is that present policies restrict low cost purchase in favour of other resources.

Gains from the removal of price discrimination follow from the assumption that price differentials between the household and industrial sectors are reduced to the cost distribution and load balancing. This appears to imply that there are no obstacles to this caused by the monopoly power of the distribution companies.

The work is closely related to the modelling presented in this report. However, there are several differences in assumptions which lead to different conclusions:

(a) we assume that exports from the Netherlands continue to be subject to policy restrictions, as are imports to the UK;
(b) we believe that demand elasticities are below those shown by Golombek *et al.*, who show elasticities greater than 1 for the residential sector;
(c) we assume that TPA does not extend to small consumers, and that distribution companies are able to continue to price discriminate. This may be extended to the ability of producers to *de facto* control on-sale of gas;
(d) the power sector, with its high rents, is explicitly included in our model;
(e) we use different estimates for parameter values;

(f) supply security is explicitly included in our model and excluded from the model by Golombek *et al.*

These different assumptions lead to the differing results obtained in this study.

Odell, P.R. [1993] 'Prospects for Natural Gas in Western Europe'. *The Energy Journal*, Vol. 13, No 3.

A review of the European gas industry arguing for major potential for expansion. Remaining gas reserves in Western Europe (including Norway) are reviewed and shown to have increased consistently over the last four decades. This is argued to be at odds with the conventional view that conserving resources by limiting production is the main policy objective. Further liberalization of the industry is seen as inevitable.

Demand growth is forecast to be strong. Production in the UK is forecast to rise, and Netherlands productivity to remain constant. The likely need for external supplies is noted, with the FSU and Algeria identified as readily able to meet demand, other producers providing niche supplies.

An increase in the netback value of gas is foreseen especially in view of a possible carbon tax.

Radetzki, M. [1994] 'World Demand for Natural Gas: History and Prospects'. *The Energy Journal*, Vol. 15, Special Issue.

A review of the world gas industry suggesting for the European market greater competition upstream and downstream, and growing consumption.

Jensen, J.T. [1994] *Gas supplies for the world market.*

A review of gas supply fundamentals, industry production cost estimates.

Stern, J.P. [1995] *The Russian Natural Gas 'Bubble' – Consequences for European Gas Markets.* Royal Institute of International Affairs.

An extensive analysis of supply, demand and transport capacity in Russia, suggesting that there is potential for large scale, low cost additional exports to Western Europe.

Dienes, L., Dobozi, I. And Radetzki, M. [1994] *Energy and Economic Reform in the Former Soviet Union.* London: Macmillan.

A general review of the consequences of reform in the energy sector in the FSU.

Radetzki, M. [1992] 'Pricing of natural gas in the West European Market', *Energy Studies Review*, Vol. 4, No 2.

This paper argues that prices to the user are those of a price discriminating monopolist, with rents going largely to producers. Evidence of this is obtained by comparing the returns of transmission companies and producers. This is forecast to change as both production and transmission become more competitive.

The paper suggests four reasons why transmission companies may not seek to profit maximize:

(a) ownership by oil companies implying that the import price of gas is in effect a transfer price;
(b) political interference in negotiations, such as countertrade, the 30% rule, and politically motivated high prices for Algerian gas;
(c) cost plus pricing which seeks to limit prices to consumers to the border price plus cost of transport, which allows the importer to bid up prices;
(d) the ability of monopolies to ensure an adequate return.

These are consistent with the satisfying model proposed in this work, except the first which does not appear valid in view of the limited control by shareholders of companies' behaviour, widespread state ownership, and the state ownership of many producers.

Mittra, B., Lucas, N. and Fells, I. [1995] 'European Energy: Balancing markets and policy'. *Energy Policy*, Vol. 23, No 8, pp. 689–701.

A review of general energy policy issues. Sources of market failure are identified as arising from monopoly, public goods, externalities (especially the environment, short termism and R&D). The first three are uncontentious while the last two are acknowledged by the author as contentious, and in this work we have rejected the short-termism argument as presented by the authors and considered fundamental R&D a case of a public good. Policy failures are also described.

Objectives for energy policy are suggested to be security of supply, access and quality standards, pollution control, and least cost supply. The authors recommend measures to encourage security of supply (including efficiency measures, a tax on imports and completion of networks, TPA, and a CO_2 tax).

Bergmann, B. [1988] *Natural Gas in Western Europe: Facing the oil price uncertainties in the 1986 oil price crisis and policy responses.* Mabro ed.

A paper noting the relationship between gas and oil prices in consumer markets and import contracts.

Percebois, J. and Valette, E. [1995] *Modelling the European Gas Market, a comparison of several scenarios.*

A model of stocks and flows of gas is used to simulate the effect of supply disruption.

B1.2. Game theory

The literature on game theory is extensive, often highly technical and much of it has limited relevance to the present study. The following review is therefore highly selective.

The Nash bargaining solution is described in standard texts (e.g. Binmore, 1992). The game theoretical approach to Cournot oligopoly is also widely covered, but in almost all cases the assumption of a linear demand curve is adopted, and the treatment given here is particular to the gas industry. There are good semi-technical accounts on the basis and limitations of game theory (e.g. Kreps (1990); Hargreaves, Heap and Varoufakis (1995)).

The specific application of game theory to oligopoly is reviewed in Phlips (1995). Explicit collusion is treated following the original work by Selten (1973) showing that 'four is few [i.e. collusive], six is many [i.e. competitive]'. The theory of tacit collusion is also reviewed, showing the tendency of the collusive outcome to be reached provided that oligopolists meet over and over again in the market (i.e. there is a repeated game).

The original empirical work on repeated Prisoners' Dilemma is due to Axelrod (1984). A survey of recent work in this area is given by Nowak, May and Sigmund (1995). There has been some work on strategies in oligopoly markets that draws on the idea of computer experimentation to derive best strategies (e.g. Binmore and Samuelson, 1992), but the emphasis has tended to be on the standard Cournot model (e.g. Dixon, Wallis and Moss, 1994). In all of this work a strong tendency towards co-operation emerging in repeated games is found.

B1.2.1. References: on game theory

Axelrod, R. [1984] *The Evolution of Cooperation.* Basic Books, New York.

Binmore, K. [1992] *Fun and Games.* Heath.

Binmore, K. and Samuelson, L. [1992] 'Evolutionary stability in repeated games played by finite automata', *Journal of Economic Theory*, 57, 278–305.

Dixon, H.D., Wallis, S. and Moss, S. [1994] *Axelrod Meets Cournot: Oligopoly and the Evolutionary Metaphor Part 1.* Discussion Paper, Department of Economics, University of York. July.

Hargreaves-Heap, S.P. and Varoufakis, Y. [1995] *Game Theory*, Routledge.

Kreps, D.M. [1990] *Game Theory and Economic Modelling.* Oxford.

Nowak, M.A., May, R.M. and Sigmund, K. [1995] 'The Arithmetic of Mutual Help'. *Scientific American*, June.

Phlips, L. [1995] *Competition Policy: A game-theoretic perspective.* Cambridge University Press.

Selten, R. [1973] *International Journal of Game Theory*, 2, 141–201.

B2. Demand

B2.1. Drivers of gas demand

The key drivers of demand are different in each sector. This discussion reviews and expands on the material in the main report. In the residential sector, number of connections, proportion of connections with space heating load, and long-term trends in consumer income and energy efficiency are the main drivers of demand. Demand is not very price sensitive. Substitution is also possible, as in other sectors, but tends to be less direct: for example, gasoil is a substitute in residential heating applications but new equipment may be required.

In the commercial sector, the price relative to gasoil is of key importance, although there is a good deal of inertia, caused by the installed base of appliances. Gas may attract an increasing environmental premium due to tightening air quality standards in urban areas, and the consequent need to move to very low sulphur gasoil. In most commercial applications, the quality of energy service tends to predominate over cost considerations, because energy costs are a small proportion of total costs. This also tends to inertia due to a lack of attention to energy costs.

In large industrial use, the relative price of gas and fuel oil is a key variable. Again, gas attracts a significant environmental premium and competes with low sulphur fuels. Oil can be used as a direct substitute for gas in many industrial applications, especially steam raising but also some process heat applications. Some industrial plant is dual fired, being able to switch readily between gas and oil.

In the power sector, the full cost of generation is the key driver. The demand for gas is therefore driven by the relative cost of gas and competing fuels, and of different generating technologies. The use of gas in combined cycle plant (CCGT) is the largest single change in the prospects for gas demand in recent years. The trend towards CCGTs is likely to be furthered by the increasing trend towards IPPs, which favours low capital cost and short lead time technologies. In the power sector, the major competing fuel is coal, either in a steam cycle or gasified for use in combined cycle.

Policy issues are potentially important influences on demand. In the past natural gas has been viewed as a premium fuel, not suitable for some applications. National policy is likely to influence the rate at which residential consumers are connected to the grid in the residential sector. Fuel choice in the power sector is also subject to the influence of national policy. For many years the EC Directive restricting the use of gas in the power sector (COM(93) 643 final) prevented the growth of large scale demand from this sector.

B2.2. Elasticities of demand

Evidence of the elasticity of gas demand is difficult to obtain because the price regime for natural gas in Western Europe has been stable, so there has been little opportunity to observe the effect of changes. Further, a key sector of demand, the power sector, is new, with a well defined pricing regime only having emerged in the special circumstances of the UK. Estimates must therefore be based on an analysis of fundamentals.

Short run elasticities of demand for gas tend to be very high as equipment is dedicated, with the exception of those industrial users who have dual firing. Longer term elasticities must include the relative cost of capital equipment. Radetzki (1992) implies a demand curve for gas that is kinked, as present here, but suggests the possibility of high elasticities below the substitution price, giving two alternative revenue maximizing points (high price/low volume and low price/high volume). This seems inherently implausible because:

(a) price elasticities below the substitution point would be expected to be low on economic principle. This is strongly supported by the experience of the UK, which has seen rapidly falling prices in the residential commercial and industrial sectors with no corresponding demand growth (see below). The demand growth is all in the power sector;
(b) a low price strategy would suggest very low marginal costs, which seems unlikely in view of the resource costs.

Each sector is now reviewed.

B2.2.1. Power sector

Above the price leading to cost parity with coal based technology, generation using gas has few advantages. Emissions from modern coal plant are within LCPD limits. USC steam technology is already proven and IGCC is likely to become so. Strategic positioning against a future carbon tax is the other main economic advantage of gas, but presently this appears to be a minor element in utilities' decision making. It would therefore be expected that gas demand would drop rapidly above the coal parity price.

Below the coal parity price it rapidly becomes a question of what determines plant drive other than economics. The most influential factors would appear to be:

(a) *Utility conservatism.* Many utilities remain profoundly conservative in their choice of fuel and technology.
(b) *Concern about security of supply.* Coal is available from several geographically and politically diverse sources. Gas is perceived in contrast as a vulnerable fuel requiring dedicated infrastructures.
(c) *National policy.* This has often influenced choice of technology most notably with the French nuclear programme, the use of indigenous coal in Germany and the construction of multi-fuel plant in Italy. This is related to the concern on security of supply.

The extent to which these concerns limit the demand for gas will depend on the electricity market environment. In an uncompetitive environment, a large discount may be required to secure large amounts of additional demand. In a competitive environment, demand may be expected to expand rapidly to its full potential at a relatively modest discount to coal parity.

B2.2.2. Commercial sector

Demand from commercial customers is expected to be price inelastic. Consumption is not greatly restricted by price as prices are a small proportion of total costs and the performance of the business is the primary concern. A cut in price is therefore unlikely to raise consumption in the market significantly.

These features extend to the portion of the demand curve where oil becomes a substitute. A large amount of inertia is likely to be present in the market, which will be exacerbated by the long lived nature of equipment, which tends to be dedicated to a single fuel. This inertia is confirmed by anecdotal evidence from the industry.

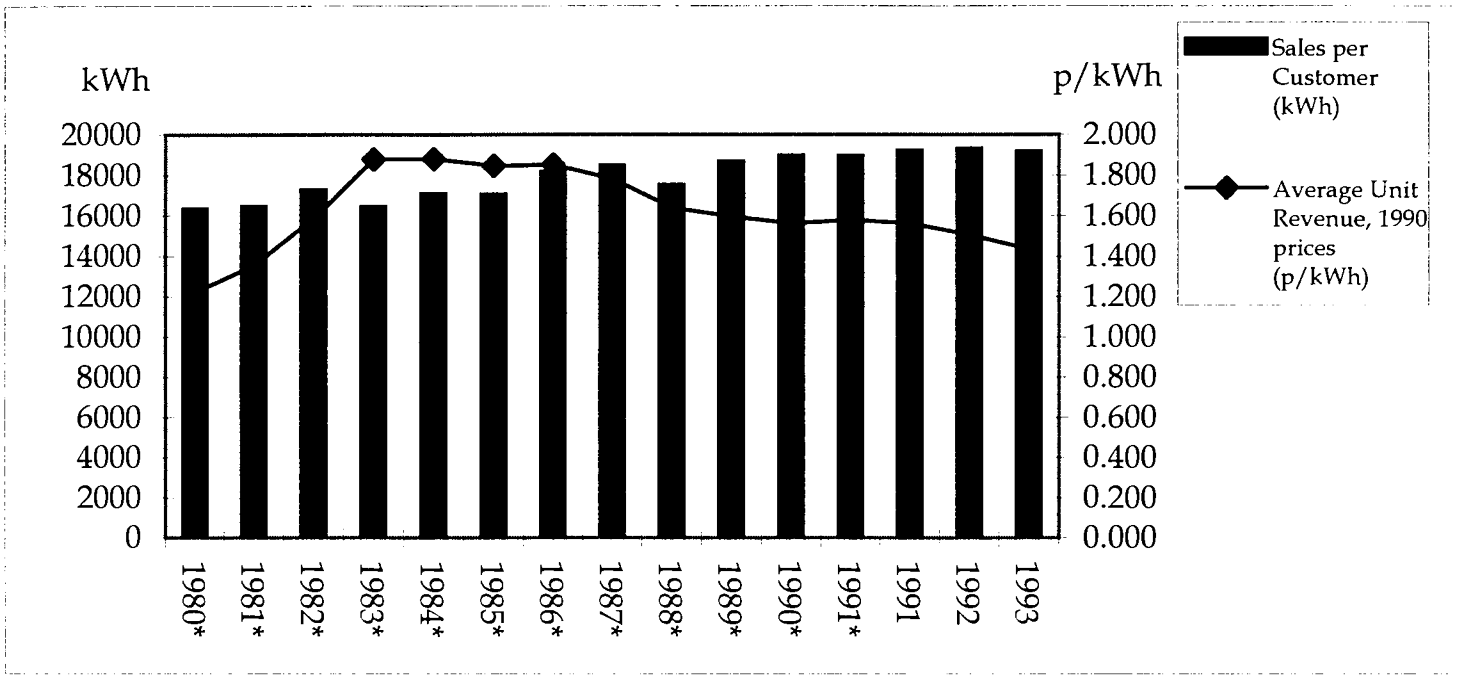
B2.2.3. Industrial sector

Gas and low sulphur fuel oil (LSFO) are close substitutes in many industrial applications, especially steam raising. There is therefore a high elasticity of demand close to thermal parity between the two fuels. This is recognized in gas pricing throughout much of Europe, most explicitly in Germany. Demand for gas is expected to be highly elastic at this point. Below this it is unclear how elastic demand is, but there seems little reason to suppose it will be highly elastic. A figure of relative prices of LSFO and gas across Europe shows only a weak correlation between market share and relative price.

B2.2.4. Residential sector

The price in this sector tends to be highly inelastic. The strongest evidence of this is from the UK market, as noted above.

Figure B2.1 British Gas residential demand, 1980–1993



* year to 31st March

Table B2.1. UK gas demand and prices, 1980–94

	1980	1981	1982	1983	1984
GDP at current prices (£million)	231772	254927	279041	304456	325852
GDP at 1990 prices (£million)	423490	418026	425252	440888	451131
Implied GDP deflator	1.827184	1.639787	1.523977	1.448117	1.384466

	1985	1986	1987	1988	1989
GDP at current prices (£million)	357344	384843	423381	471430	515957
GDP at 1990 prices (£million)	468071	488122	511615	537215	548940
Implied GDP deflator	1.309861	1.268367	1.208403	1.139544	1.063926

	1990	1991	1992	1993	1994
GDP at current prices (£million)	551118	575321	597242	630707	668866
GDP at 1990 prices (£million)	551118	540038	537448	549589	570722
Implied GDP deflator	1	0.938672	0.899883	0.871386	0.853268

	1980*	1981*	1982*	1983*	1984*
Residential Gas Sales (GWh)[a]	236626	242516	257990	248847	263529
Number of Residental Customers (Thousands)	14485	14725	14929	15135	15427
Sales per Customer (kWh)	16336	16470	17281	16442	17082
Standing Charge (p/day)[b]			8.8	10.1	10.1
Unit Charge (p/kWh)[b]			0.928	1.143	1.143
Standing Charge, 1990 prices (p/day)	0.00	0.00	13.41	14.63	13.98
Unit Charge, 1990 prices (p/kWh)	0.000	0.000	1.414	1.655	1.582
Average Unit Revenue (p/kWh)[b]	0.669	0.826	1.041	1.297	1.358
Average Unit Revenue, 1990 prices (p/kWh)	1.222	1.354	1.586	1.878	1.880

	1985*	1986*	1987*	1988*	1989*
Residential Gas Sales (GWh)a	267925	290082	299812	288968	314670
Number of Residental Customers (Thousands)	15715	15973	16235	16495	16842
Sales per Customer (kWh)	17049	18161	18467	17519	18684
Standing Charge (p/day)b	10.1	10.1	9	8.5	9.1
Unit Charge (p/kWh)b	1.201	1.262	1.297	1.239	1.314
Standing Charge, 1990 prices (p/day)	13.23	12.81	10.88	9.69	9.68
Unit Charge, 1990 prices (p/kWh)	1.573	1.601	1.567	1.412	1.398
Average Unit Revenue (p/kWh)b	1.410	1.460	1.475	1.439	1.501
Average Unit Revenue, 1990 prices (p/kWh)	1.847	1.852	1.782	1.640	1.597

	1990*	1991*	1991	1992	1993	1994
Residential Gas Sales (GWh)a	323433	328093	336416	343981	346693	355228
Number of Residental Customers (Thousands)	17054	17311	17510	17802	18094	18359
Sales per Customer (kWh)	18965	18953	19213	19323	19161	19349
Standing Charge (p/day)b	9.5	10.3	10.3	10.3	10.1	10.1
Unit Charge (p/kWh)b	1.358	1.512	1.566	1.507	1.477	1.477
Standing Charge, 1990 prices (p/day)	9.50	9.67	9.67	9.27	8.80	8.62
Unit Charge, 1990 prices (p/kWh)	1.358	1.419	1.470	1.356	1.287	1.260
Average Unit Revenue (p/kWh)b	1.562	1.683	1.738	1.729	1.682	N/A
Average Unit Revenue, 1990 prices (p/kWh)	1.562	1.580	1.564	1.507	1.435	N/A

*Year ended 31 March.

[a] Tariff sales only. Figures for 1989 onwards are adjusted to average temperature.

[b] Where prices changed during the course of a year the price in force for the majority of the year is given.

B2.3. Effect of elasticities on prices under monopoly

Consider a much simplified market for gas which involved a monopoly producer selling to a monopsony transmission company which sells to the final market. Let the unit price that the producer sells to the transmission company be P_p, and the price that the transmission company adds to this when selling to the final market be P_t. The price which consumers face is then $P = P_p + P_t$. Suppose that both producer and distributor have costs of $C_p(Q)$ and $C_t(Q)$ respectively, and that the demand for gas is linear and described by $Q = a - b*P$, where Q is the total number of units consumers buy at price P. Further assume that the demand function and both cost functions are common knowledge to the transmission company and the distribution company. The profits are then:

$$\Pi_p = Q * P_p - C_p(Q) = (a - bP_p - bP_t) * P_p - C_p(Q)\text{; and}$$

$$\Pi_t = Q * Pt - Ct(Q) = (a - bP_p - bP_t) * P_t - C_t(Q)$$

for the producer and the distributor respectively. If both the producer and the distributor set their prices simultaneously, then the price reaction functions are:

$$P_p = \frac{a - bP_t + bc_p}{2b}\text{; and}$$

$$P_t = \frac{1 - P_p + c_t}{2b}$$

where c_p and c_t are the marginal costs of the producer and the transmission company respectively.

The Nash equilibrium occurs when both these optimal reaction functions are simultaneously satisfied. This results in prices:

$$P_p = \frac{a - bc_t + 2bc_p}{3b}\text{; and}$$

$$P_t = \frac{a - bc_p + 2bc_t}{3b}$$

If we further assume that both companies have constant average costs (i.e. average cost equals marginal cost), the Nash equilibrium profits are then:

$$\Pi_p = \frac{(a - bc_p - bc_t)^2}{9b^2}$$

$$\Pi_t = \frac{(a - bc_p - bc_t)^2}{9b}$$

B2.4. Monopoly–monopsony analysis under a kinked demand curve

Consider a demand curve which is piece-wise linear, with $Q = a_1 - b_1 P$ above the price of oil and $Q = a_2 - b_2 P$ below the price of oil. This demand curve thus has a kink at the oil price. We denote this price, P_k.

$$Q = a_1 - b_1(P_p + P_t) \text{ for } P_p + P_t \geq P_k$$

$$Q = a_2 - b_2(P_p + P_t) \text{ for } P_p + P_t \leq P_k$$

Under this piece-wise linear demand curve, profit for the producer is:

$$\Pi_p = (a_1 - b_1 P_p - b_1 P_t) * P_p - C_p(Q) \text{ when } P_p + P_t \geq P_k$$

$$\Pi_p = (a_2 - b_2 P_p - b_2 P_t) * P_p - C_p(Q) \text{ when } P_p + P_t \leq P_k$$

Similarly, profit for the distributing company is:

$$\Pi_t = (a_1 - b_1 P_p - b_1 P_t) * P_t - C_t(Q) \text{ when } P_p + P_t \geq P_k$$

$$\Pi_t = (a_2 - b_2 P_p - b_2 P_t) * P_t - C_t(Q) \text{ when } P_p + P_t \leq P_k$$

We consider a one-off meeting of the two companies to decide prices P_p and P_t. We assume, first, that the two companies set their prices simultaneously and also that prices are set at this level for a long period of time. This latter assumption is plausible in the current market structure of the gas industry which has long-term contracts.

A Nash equilibrium in the two companies' pricing strategies requires the following technical conditions, where P represents the market price,

$$P = P_p + P_t.$$

$$\frac{d\Pi_p}{dP_p} \leq 0 \text{ below } P; \quad \frac{d\Pi_p}{dP_p} \geq 0 \text{ above } P;$$

$$\frac{d\Pi_t}{dP_t} \leq 0 \text{ below } P; \quad \frac{d\Pi_t}{dP_t} \geq 0 \text{ above } P.$$

If the demand curve were continuously differentiable (as, for example, with a linear demand curve with no kink), both of these inequalities would become exact equalities. In that case, both companies would have the standard profit maximizing procedure of setting marginal revenue equal to marginal cost.

However, the demand curve which we have used is not differentiable at the kink point. More precisely, the slope of the demand curve above the kink point is very low, given by b_1, while the slope of the demand curve below the kink point is very high, given by b_2. Precisely at the kink point, the slope of the demand curve changes instantaneously from b_1 to b_2. It is therefore possible that, if the final equilibrium market price is equal to the oil price P_k, the companies are unable to price so that marginal revenue equals marginal cost.

For a Nash equilibrium in pricing strategies to hold, both the producer and the transmission company must be unwilling to change their prices, given the other's price. Thus, profit for both companies must be decreasing in price above the equilibrium price and increasing in price below the equilibrium price. The technical equations above are the formalization of this.

We can divide the companies' pricing strategies into three potential outcomes:

(a) If the Nash equilibrium is above the kink, then the demand curve is differentiable, with slope b_1, and the derivative of the two profit functions with respect to their prices are equal to zero.
(b) If the Nash equilibrium is below the kink, then the demand curve is also differentiable, with slope b_2, and the derivative of the two profit functions with respect to their prices are equal to zero.
(c) If the Nash equilibrium is at the kink, point then the two companies' prices, P_p and P_t are such that $P_p+P_t=P_k$.

The first two outcomes represent the standard textbook outcome of a monopoly selling to a monopsonist. The third outcome is a possibility which could result if the elasticity of demand above the kink were sufficiently high. In that case, neither producer nor distributor would want to increase price because of the rapidly falling demand above that point. The result is multiple Nash equilibria which includes the many possibilities where the sum of the producer's and the distributor's price equals the kink (oil) price.

If the final market price is equal to the kink price, then there is a minimum price that the producer and the distributor will accept. This is determined by the elasticity of demand above the kink point. The higher the elasticity of demand, the lower the profit margin that either party will accept before raising the combined price above the kink point. More precisely, under the assumption of constant average costs, the minimum margins that either company will accept are given by:

1. $$P_p - c_p \geq \frac{P_k}{\varepsilon}$$

2. $$P_t - ct \geq \frac{P_k}{\varepsilon}$$

where the elasticity (ε) is evaluated just above the kink price.

The minimum proportion of rents (price less average cost) that either companies will accept is:

$$Min\% = \frac{P_k}{P_k - c_p - c_t} * \frac{1}{\varepsilon}$$

Thus, a higher elasticity of demand just above the oil price, means that both companies would accept a lower share of the total rents accruing from the uncompetitive market. The higher the elasticity, the lower the share that they will accept. We note that this minimum condition is the same for both companies, but it need not be so.

If we assume that the producer 'moves first' by setting a price to the transmission company, it will set its price to get the maximum share of the rents. Thus, it will price so that the above inequality holds exactly.

B2.5. Summary of results

The theoretical analysis can be generalized to give the following results:

(a) A monopoly producer under TPA will never choose to lower price if the elasticity of demand is less than 1, even if costs are low. The higher costs are, the more elastic demand will need to be. This implies that a monopolist will never seek to expand volumes if it implies lowering price below the kink point in the demand curves set by the price of competing fuels, and will always price at least at this level. The extent to which this extends to oligopolists is discussed in the text.

(b) A monopoly producer under TPA will choose to raise price above the kink point in the demand curves only if margins are small and demand is not highly elastic.

(c) If the transmission company can price discriminate, it will have little incentive to raise price above the kink point and restrict the market. It may choose to expand demand by selling to some low value customers, but if price discrimination is imperfect, this is a risky strategy as it risks lowering total revenues.

These considerations together imply a strong tendency for monopoly prices at the kink point.

B2.6. Comparison of demand forecasts

Several industry participants have made their own forecasts of demand. These are compared in Table B2.2, which is based on that published by Stern (1995). They show a range around 450 bcm p.a. by 2010 for Western Europe. Most of the forecasts have in common an assumption of continuation of existing price relationships between oil and gas. The conventional wisdom scenario is towards the upper end of the range shown, but appears credible in view of the assumptions.

Table B2.2. Comparison of gas demand forecast by industry participants

	1993	2000	2010
EU (conventional + wisdom)	267 (1992)	378	506
OECD[1]	329	380–400	440–470
Central/Eastern[2]	67	80–90	110–125
Total Europe[2]			530–560
OECD[3]		340	440
Western Europe[4]			400
Eastern Europe[4]			100
Western Europe[5]		360–400	400–480
Western Europe[6]			400–430
Western Europe[7]			500
Central/Eastern Europe[7]			94
Western Europe[8]			400–460
Central/Eastern Europe[8]			100–120
Western Europe[9]			450
Western Europe[10]			500

Note: This work based on 1bcm = 1.201 million toe (38MJ/m^3 GCV for gas).

[1] *The Development of International Gas Markets* (Paris: Cedigaz, 1994).

[2] Gazprom forecast from R. I. Vyakhirev, *The Russian Gas Industry in the Context of the Russian and World Economy*, paper presented to the Conference on 'Natural Gas: Trade and Investment Opportunities in Russia and the CIS', Royal Institute of International Affairs, London, 13–14 October 1994.

[3] International Energy Agency, *World Energy Outlook* (Paris, OECD, 1994).

[4] Statoil estimates; Karen Fossli, 'Western Europe Gas Needs to Rise 60%', *Financial Times*, 4 November 1993.

[5] Shell International Gas.

[6] Ruhrgas forecast from Gerhard Enseling, 'Analysing Future Sources of Gas Supply for Europe', paper presented at the European Gas Strategies '95 Conference, Amsterdam, February 1995.

[7] Purvin and Geertz forecast from 'European Gas Demand Will Be Strong to 2010; Costs Cloud Supply Picture', *Oil and Gas Journal*, 16 May, 1994, pp. 32–53.

[8] SNAM forecast from Dominico Dispenza, 'Europe's Need for Gas Imports Destined to Grow', *Oil and Gas Journal*, 13 March 1995, pp. 45–48.

[9] Wintershall.

[10] Wood Mackenzie.

Table B2.3. Market share of gas by sector in EU Member States, 1993, mtoe (%)

	EU	Belgium	Denmark	France	Germany	Greece	Ireland
Commercial and Other	32.82 (24.5)	1.30 (40.0)	0.35 (11.9)	7.8 (23.3)	8.22 (23.2)	0.01 (0.5)	0.15 (11.1)
Industrial	77.10 (25.9)	3.43 (25.0)	0.56 (21.5)	12.33 (27.4)	18.81 (23.4)	0.06 (1.6)	0.8 (38.1)
Residential	87.00 (39.6)	3.03 (33.3)	0.58 (12.7)	8.06 (33.5)	19.02 (30.9)	0 (0)	0.22 (11.0)
Feedstock	10.28 (19.4)	0.62 (25.0)	0 (0)	2.09 (23.1)	1.33 (8.3)	0.06 (54.5)	0.41 (100.0)
Power Generation (inc CHP)	31.25 (6.4)	1.61 (9.2)	0.42 (5.3)	0.49 (0.5)	9.42 (6.7)	0.02 (0.2)	0.96 (27.8)

	Italy	Luxembourg	Netherlands	Portugal	Spain	United Kingdom
Commercial and Other	0.10 (1.2)	0.02 (18.2)	7.24 (64.9)	0.02 (1.7)	0.35 (6.0)	7.22 (36.4)
Industrial	14.46 (36.0)	0.3 (17.6)	9.1 (47.4)	0 (0)	4.27 (19.6)	10.29 (26.8)
Residential	18.35 (57.2)	0.17 (5.3)	8.5 (81.0)	0.04 (2.2)	0.94 (11.5)	26.32 (63.8)
Feedstock	0.96 (18.5)	0 (0)	2.31 (38.3)	1.22 (100.0)	0.39 (14.8)	1.81 (22.0)
Power Generation (inc CHP)	8.11 (18.8)	0.01 (4.8)	8.7 (54.0)	0 (0)	0.17 (0.5)	8.13 (10.9)

Source: OECD IEA 1993.

B3. Supply

Table B3.1. Reserves, production and r/p ratios

	Reserves (bcm)	Production (bcm)	r/p
Netherlands	1,900	70	27.1
United Kingdom	600	69	9.6
Germany	300	16	19.5
Other Western Europe (mainly Italy)	600	33	18.8
Norway	2,000	30	65.6
Algeria	3,600	50	72
Russia	48,100	598	80.5
Ukraine	1,100	17	63.2
Uzbekistan	1,900	46	40.2
Turkmenistan	2,900	35	81.6
Other FSU	2,000	11	>100
Iran	21,000	33	>100
Qatar	7,100	14	>100
Libya	1,300	7	>100
Nigeria	3,400	4	>100
Venezuela	3,700	27	>100

Source: BP, Cedigas.

Table B3.2. Full cost of gas: delivered to European Union border

Country of origin	Production costs (US$/MMBtu)	Transport costs (US$/MMBtu)	Total resource costs (US$/MMBtu)	Transit costs (US$/MMBtu)	Total costs (US$/MMBtu)
Netherlands: Groningen*	0.10	0.15	0.25	0.00	0.25
Netherlands: onshore	0.60	0.15	0.75	0.00	0.75
Algeria to Transmed to Italy	0.50	0.45	0.95	0.11	1.06
Norway: Ekofisk to Emden	1.00	0.34	1.34	0.00	1.34
Algeria: Maghreb to Spain	0.50	0.75	1.25	0.14	1.39
Norway: East Sleipner to Emden	1.10	0.46	1.56	0.00	1.56
Netherlands: North Sea	1.00	0.60	1.60	0.00	1.60
Norway: Frigg to St. Fergus	1.50	0.27	1.77	0.00	1.77
Norway: Heimdal to Emden	1.25	0.57	1.82	0.00	1.82
Norway: East Sleipner to Zeebrugge	1.10	0.79	1.89	0.00	1.89
Norway: Troll to Emden	1.20	0.76	1.96	0.00	1.96
Algeria: LNG Monitor	0.50	1.49	1.99	0.00	1.99
UK: Interconnector to Zeebrugge	1.50	0.60	2.10	0.00	2.10
Norway: Statfjord to Emden	1.25	0.89	2.14	0.00	2.14
Norway: Tordis to Emden	1.30	0.89	2.19	0.00	2.19
Norway: Troll to Zeebrugge	1.20	1.09	2.29	0.00	2.29
Norway: Oseberg to Emden	1.50	0.81	2.31	0.00	2.31
Libya: LNG (10 bcm) to Italy	0.50	1.93	2.43	0.00	2.43
Norway: West Sleipner to Emden	2.20	0.46	2.66	0.00	2.66
Libya: LNG (4 bcm) to Italy	0.50	2.21	2.71	0.00	2.71
Egypt: LNG (5 bcm) to Italy	0.70	2.11	2.81	0.00	2.81
Norway: Haltenbanken to Emden	1.42	1.50	2.92	0.00	2.92
Nigeria: old boats to Italy	0.70	2.27	2.97	0.00	2.97
Norway: West Sleipner to Zeebrugge	2.20	0.79	2.99	0.00	2.99
Russia: Western Siberia to EUR-12	0.50	1.88	2.38	0.84	3.22
Norway: Haltenbanken to Zeebrugge	1.42	1.83	3.25	0.00	3.25
Qatar: pipeline Ashkelon to LNG Italy	0.50	2.78	3.28	0.00	3.28
Qatar: pipeline Side Kerir to LNG to Italy	0.50	2.82	3.32	0.00	3.32
Russia: Yamal to EUR-12	0.75	1.98	2.73	0.64	3.37
Nigeria: LNG to Italy**	0.70	2.70	3.40	0.00	3.40
Qatar: LNG to Italy	0.50	3.01	3.51	0.00	3.51
Oman: LNG to Italy	0.50	3.07	3.57	0.00	3.57
Iran: pipeline Turkey to LNG Italy	0.50	2.82	3.32	0.43	3.75
Venezuela: LNG to EU 12	1.10	2.73	3.83	0.00	3.83
Iran: pipeline Turkey to Italy	0.5	2.04	2.54	1.55	4.09
Norway: Barents Sea to LNG Wilhelmshafen	1.90	2.27	4.17	0.00	4.17
Norway: Barents Sea to LNG Zeebrugge	1.90	2.30	4.20	0.00	4.20
Turkmenistan: pipeline Turkey to LNG Italy	0.50	2.85	3.35	0.90	4.25
Turkmenistan: pipeline Turkey to Italy	0.50	1.88	2.38	2.00	4.38
Turkmenistan: pipeline FSU to Germany	0.50	1.99	2.49	2.00	4.49
Russia: new gas Barents Sea to EUR-12	1.50	3.15	4.65	0.00	4.65
Qatar: pipeline Turkey to Italy	0.50	1.85	2.35	2.35	4.70

Source: IEA.

Notes:

EUR-12 is the European Union as of 1994 i.e. before expansion

* Delivered at border to neighbouring countries

** If used tankers are used, the total cost at the EU border is US$2.97/MMbtu

10% discount rate used to calculate transport costs

B4. Value of gas

B4.1. Value of gas in power generation

This section shows the value of gas against other fuels. This is high, even when very favourable assumptions are used for other types of plant (e.g. 42% thermal efficiency for coal is higher than typically achieved).

Table B4.1. Value of gas in power generation

Assumptions:		
	Load factor	**85%**
	Discount rate (real)	**10%**
	Year 2000 thermal efficiencies	

	GAS CCGT	COAL PF+FGD	COAL USC	COAL IGCC	OIL IGCC	ORIMULS. IGCC	LSFO STEAM	NUCLEAR
Capital cost (US$/kW)	650	1300	1500	1600	1450	1450	1000	2400
Interest on capex dur. constr. (%)	9%	17%	18%	17%	17%	17%	14%	26%
Project life (years)	20	40	40	30	30	30	40	35
Pre-tax discount rate (%)	10%	10%	10%	10%	10%	10%	10%	10%
Annuity factor (%)	12%	10%	10%	11%	11%	11%	10%	10%
Capex at commisioning	710	1515	1773	1865	1690	1690	1136	3030
Annual capital cost ($/kW)	83	155	181	198	179	179	116	314
Fixed O&M ($/kW p.a.)*	21	35	35	35	33	33	30	57
Variable O&M (c/kWh)	0.20	0.30	0.53	0.30	0.25	0.28	0.28	0.40
Load factor (%)	85%	85%	85%	85%	85%	85%	85%	85%
Electricity per kW (kWh)	7446	7446	7446	7446	7446	7446	7446	7446
Capex (c/kWh)	**1.1**	**2.1**	**2.4**	**2.7**	**2.4**	**2.4**	**1.6**	**4.2**
Opex (c/kWh)	**0.5**	**0.8**	**1.0**	**0.8**	**0.7**	**0.7**	**0.7**	**1.2**
Capex + opex (c/kWh)	1.6	2.9	3.4	3.4	3.1	3.1	2.2	5.4
Fuel price	**4.20**	**50**	**50**	**50**	**70**	**60**	**120**	**0.5**
Thermal efficiency (net - LHV)	55%	42%	45%	49%	49%	49%	39%	100%
Fuel cost (c/kWh output)	2.8	1.6	1.6	1.5	1.3	1.6	2.7	0.5
Total cost of electricity (c/kWh)	**4.4**	**4.4**	**5.0**	**4.9**	**4.4**	**4.8**	**5.0**	**5.9**
Fuel price units	$/MMBTU	$/TONNE 6500 KCAL /KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 9750KCAL KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 9750KCAL KG NCV	c/kWh

Table B4.2. Value of gas in power generation

Assumptions:	Load factor	85%
	Discount rate (real)	10%

	GAS CCGT	COAL PF+FGD	COAL USC	COAL IGCC	OIL IGCC	ORIMULS. IGCC	LSFO STEAM	NUCLEAR
Capital cost (US$/kW)	650	1300	1500	1600	1450	1450	1000	2400
Interest on capex dur. constr. (%)	9%	17%	18%	17%	17%	17%	14%	26%
Project life (years)	20	40	40	30	30	30	40	35
Pre-tax discount rate (%)	10%	10%	10%	10%	10%	10%	10%	10%
Annuity factor (%)	12%	10%	10%	11%	11%	11%	10%	10%
Capex at commisioning	710	1515	1773	1865	1690	1690	1136	3030
Annual capital cost ($/kW)	83	155	181	198	179	179	116	314
Fixed O&M ($/kW p.a.)*	21	35	35	35	33	33	30	57
Variable O&M (c/kWh)	0.20	0.30	0.53	0.30	0.25	0.28	0.28	0.40
Load factor (%)	85%	85%	85%	85%	85%	85%	85%	85%
Electricity per kW (kWh)	7446	7446	7446	7446	7446	7446	7446	7446
Capex (c/kWh)	**1.1**	**2.1**	**2.4**	**2.7**	**2.4**	**2.4**	**1.6**	**4.2**
Opex (c/kWh)	**0.5**	**0.8**	**1.0**	**0.8**	**0.7**	**0.7**	**0.7**	**1.2**
Capex + opex (c/kWh)	1.6	2.9	3.4	3.4	3.1	3.1	2.2	5.4
Fuel price	**4.70**	**50**	**50**	**50**	**70**	**60**	**120**	**0.5**
Thermal efficiency (net - LHV)	55%	42%	45%	49%	49%	49%	39%	100%
Fuel cost (c/kWh output)	3.2	1.6	1.6	1.5	1.3	1.6	2.7	0.5
Total cost of electricity (c/kWh)	**4.8**	**4.4**	**5.0**	**4.9**	**4.4**	**4.8**	**5.0**	**5.9**
Fuel price units	$/MMBTU	$/TONNE 6500 KCAL /KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 9750KCAL KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 9750KCAL KG NCV	c/kWh

Table B4.3. Value of gas in power generation

Assumptions: Load factor **85%**
Discount rate (real) **10%**

	GAS CCGT	COAL PF+FGD	COAL USC	COAL IGCC	OIL IGCC	ORIMULS. IGCC	LSFO STEAM	NUCLEAR
Capital cost (US$/kW)	650	1300	1500	1600	1450	1450	1000	2400
Interest on capex dur. constr. (%)	9%	17%	18%	17%	17%	17%	14%	26%
Project life (years)	20	40	40	30	30	30	40	35
Pre-tax discount rate (%)	10%	10%	10%	10%	10%	10%	10%	10%
Annuity factor (%)	12%	10%	10%	11%	11%	11%	10%	10%
Capex at commisioning	710	1515	1773	1865	1690	1690	1136	3030
Annual capital cost ($/kW)	83	155	181	198	179	179	116	314
Fixed O&M ($/kW p.a.)*	21	35	35	35	33	33	30	57
Variable O&M (c/kWh)	0.20	0.30	0.53	0.30	0.25	0.28	0.28	0.40
Load factor (%)	85%	85%	85%	85%	85%	85%	85%	85%
Electricity per KW (kWh)	7446	7446	7446	7446	7446	7446	7446	7446
Capex (c/kWh)	**1.1**	**2.1**	**2.4**	**2.7**	**2.4**	**2.4**	**1.6**	**4.2**
Opex (c/kWh)	**0.5**	**0.8**	**1.0**	**0.8**	**0.7**	**0.7**	**0.7**	**1.2**
Capex + opex (c/kWh)	1.6	2.9	3.4	3.4	3.1	3.1	2.2	5.4
Fuel price	**5.00**	**50**	**50**	**50**	**70**	**60**	**120**	**0.5**
Thermal efficiency (net - LHV)	55%	42%	45%	49%	49%	49%	39%	100%
Fuel cost (c/kWh output)	3.4	1.6	1.6	1.5	1.3	1.6	2.7	0.5
Total cost of electricity (c/kWh)	**5.0**	**4.4**	**5.0**	**4.9**	**4.4**	**4.8**	**5.0**	**5.9**
Fuel price units	$/MMBTU	$/TONNE 6500 KCAL /KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 9750KCAL KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 9750KCAL KG NCV	c/kWh

Table B4.4. Value of gas in power generation

Assumptions:	Load factor	85%
	Discount rate (real)	10%

	GAS CCGT	COAL PF+FGD	COAL USC	COAL IGCC	OIL IGCC	ORIMULS. IGCC	LSFO STEAM	NUCLEAR
Capital cost (US$/kW)	650	1300	1500	1600	1450	1450	1000	2400
Interest on capex dur. constr. (%)	9%	17%	18%	17%	17%	17%	14%	26%
Project life (years)	20	40	40	30	30	30	40	35
Pre-tax discount rate (%)	10%	10%	10%	10%	10%	10%	10%	10%
Annuity factor (%)	12%	10%	10%	11%	11%	11%	10%	10%
Capex at commisioning	710	1515	1773	1865	1690	1690	1136	3030
Annual capital cost ($/kW)	83	155	181	198	179	179	116	314
Fixed O&M ($/kW p.a.)*	21	35	35	35	33	33	30	57
Variable O&M (c/kWh)	0.20	0.30	0.53	0.30	0.25	0.28	0.28	0.40
Load factor (%)	85%	85%	85%	85%	85%	85%	85%	85%
Electricity per kW (kWh)	7446	7446	7446	7446	7446	7446	7446	7446
Capex (c/kWh)	**1.1**	**2.1**	**2.4**	**2.7**	**2.4**	**2.4**	**1.6**	**4.2**
Opex (c/kWh)	**0.5**	**0.8**	**1.0**	**0.8**	**0.7**	**0.7**	**0.7**	**1.2**
Capex + opex (c/kWh)	1.6	2.9	3.4	3.4	3.1	3.1	2.2	5.4
Fuel price	**6.30**	**50**	**50**	**50**	**70**	**60**	**120**	**0.5**
Thermal efficiency (net - LHV)	55%	42%	45%	49%	49%	49%	39%	100%
Fuel cost (c/kWh output)	4.3	1.6	1.6	1.5	1.3	1.6	2.7	0.5
Total cost of electricity (c/kWh)	**5.9**	**4.4**	**5.0**	**4.9**	**4.4**	**4.8**	**5.0**	**5.9**
Fuel price units	$/MMBTU	$/TONNE 6500 KCAL /KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 9750KCAL KG NCV	$/TONNE 6500 KCAL /KG NCV	$/TONNE 9750KCAL KG NCV	c/kWh

B5. Taxes on gas and competing fuels

Table B5.1. Domestic gas prices and taxes

Gas taxes in the EU *per Gigajoule*	**Category**	Prices (ECU) Households D 1 (annual cons. 8.37 GJ)			Prices (ECU) Households D 2 (annual cons. 16.74 GJ)			Prices (ECU) Households D 3 (annual cons. 83.7 GJ)			Prices (ECU) Households D 3b (annual cons. 125.6 GJ)			Prices (ECU) Households D 4 (annual cons. 1,047 GJ)		
Country	**Region**	VAT	Other tax	Total tax	VAT	Other tax	Total tax	VAT	Other tax	Total tax	VAT	Other tax	Total tax	VAT	Other tax	Total tax
Belgium	Brussels	2.69	0.34	3.03	2.49	0.34	2.83	1.47	0.34	1.81	1.39	0.34	1.73	1.17	0.34	1.51
Denmark	Copenhagen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	National territory	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Germany	Hamburg	2.53	0.51	3.04	2.03	0.52	2.55	1.15	0.52	1.67	1.11	0.52	1.63	0.95	0.52	1.47
	Hanover	2.24	0.52	2.76	1.76	0.52	2.28	1.13	0.52	1.65	1.08	0.52	1.60	0.99	0.52	1.51
	Weser-Ems	2.08	0.52	2.60	1.57	0.52	2.09	0.98	0.52	1.50	0.93	0.52	1.45	0.81	0.52	1.33
	Dortmund	2.62	0.52	3.14	1.84	0.51	2.35	1.13	0.52	1.65	1.04	0.52	1.56	0.99	0.51	1.50
	Dusseldorf	2.46	0.52	2.98	1.86	0.51	2.37	1.20	0.51	1.71	1.13	0.51	1.64	1.04	0.52	1.56
	Frankfurt/Main	2.49	0.52	3.01	1.90	0.51	2.41	1.11	0.52	1.63	1.01	0.52	1.53	0.95	0.52	1.47
	Stuttgart	2.73	0.52	3.25	2.27	0.51	2.78	1.34	0.52	1.86	1.23	0.52	1.75	1.00	0.52	1.52
	Munich	2.15	0.51	2.66	1.70	0.52	2.22	1.28	0.52	1.80	1.17	0.52	1.69	1.01	0.51	1.52
	Berlin	2.42	0.52	2.94	2.42	0.52	2.94	1.43	0.51	1.94	1.42	0.52	1.94	1.25	0.52	1.77
	Dresden	2.93	0.52	3.45	2.16	0.52	2.68	1.28	0.52	1.80	1.19	0.52	1.71	1.00	0.52	1.52
Spain	Madrid	1.84	-	1.84	1.62	-	1.62	1.28	-	1.28	1.24	-	1.24	0.88	-	0.88
	Barcelona	1.84	-	1.84	1.62	-	1.62	1.28	-	1.28	1.24	-	1.24	0.88	-	0.88
	Valencia	1.84	-	1.84	1.62	-	1.62	1.28	-	1.28	1.24	-	1.24	0.88	-	0.88
	North & East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
France	Lille	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Paris	1.95	-	1.95	1.86	-	1.86	1.22	-	1.22	1.15	-	1.15	1.05	-	1.05
	Strasbourg	2.77	-	2.77	2.39	-	2.39	1.39	-	1.39	1.38	-	1.38	1.26	-	1.26
	Marseille	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Lyon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Toulouse	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ireland	Dublin	2.25	-	2.25	1.91	-	1.91	0.92	-	0.92	0.92	-	0.92	0.92	-	0.92
Italy	Milan	0.85	0.83	1.68	0.77	0.82	1.59	2.35	3.93	6.28	2.35	4.02	6.37	2.21	4.21	6.42
	Turin	0.87	1.03	1.90	0.76	1.04	1.80	2.20	4.48	6.68	2.19	4.57	6.76	2.28	4.76	7.04
	Genoa	0.98	1.03	2.01	0.88	1.03	1.91	2.31	4.48	6.79	2.32	4.77	7.09	2.32	4.76	7.08
	Rome	0.97	0.82	1.79	0.87	0.82	1.69	2.35	3.93	6.28	2.35	4.02	6.37	2.60	4.21	6.81
	Naples	1.07	0.79	1.86	0.97	0.78	1.75	1.28	3.16	4.44	1.27	3.26	4.53	1.28	3.47	4.75
Luxembourg	Luxembourg -ville	0.70	-	0.70	0.60	-	0.60	0.31	-	0.31	0.29	-	0.29	0.29	-	0.29
Netherlands	Rotterdam	1.94	0.27	2.21	1.46	0.27	1.73	1.09	0.27	1.36	1.05	0.28	1.33	1.00	0.27	1.27
Portugal	Lisbon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
United Kingdom	London	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Leeds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Birmingham	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Source: Gas Prices 1990-94, Eurostat, 1994.

Table B5.2. Industrial gas prices and taxes

Gas taxes in the EU *per Gigajoule (1994-1)*	Category	Prices (ECU) Industry I 1 (annual cons. 418.6 GJ)			Prices (ECU) Industry I 2 (annual cons. 4,186 GJ)			Prices (ECU) Industry I 3-1 (annual cons. 41,860 GJ)			Prices (ECU) Industry I 3-2 (annual cons. 41,860 GJ)			Prices (ECU) Industry I 4-1 (annual cons. 418,600 GJ)			Prices (ECU) Industry I 4-2 (annual cons. 418,600 GJ)			Prices (ECU) Industry I 5 (annual cons. 4,186,000 GJ)		
Country	**Region**	VAT	Other taxes	Tot taxes	VAT	Other taxes	Tot taxes	VAT	Other taxes	Tot taxes	VAT	Other taxes	Tot taxes	VAT	Other taxes	Tot taxes	VAT	Other taxes	Tot taxes	VAT	Other taxes	Tot taxes
Belgium	National territory	1.30	0.34	1.64	0.96	-	0.96	0.76	-	0.76	0.61	-	0.61	0.61	-	0.61	0.56	-	0.56	0.48	-	0.48
Denmark	National territory	1.35	-	1.35	1.29	-	1.29	0.82	-	0.82	0.82	-	0.82	0.63	-	0.63	0.63	-	0.63	n.a.	n.a.	n.a.
Germany	Hamburg	0.95	0.52	1.47	0.94	0.52	1.46	0.87	0.51	1.38	0.79	0.52	1.31	0.68	0.51	1.19	0.64	0.52	1.16	0.38	0.49	0.87
	Hanover	1.08	0.52	1.60	0.88	0.51	1.39	0.77	0.52	1.29	0.76	0.52	1.28	0.74	0.52	1.26	0.53	0.49	1.02	0.38	0.49	0.87
	Weser-Ems	0.83	0.52	1.35	0.80	0.52	1.32	0.66	0.51	1.17	0.66	0.51	1.17	0.55	0.51	1.06	0.55	0.51	1.06	0.50	0.52	1.02
	Dortmund	0.98	0.52	1.50	0.80	0.52	1.32	0.77	0.52	1.29	0.74	0.52	1.26	0.70	0.52	1.22	0.68	0.52	1.20	0.41	0.52	0.93
	Dusseldorf	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Frankfurt/Main	0.95	0.52	1.47	0.89	0.52	1.41	0.79	0.52	1.31	0.77	0.51	1.28	0.74	0.52	1.26	0.71	0.52	1.23	0.28	0.35	0.63
	Stuttgart	1.03	0.52	1.55	0.95	0.51	1.46	0.91	0.51	1.42	0.83	0.51	1.34	0.77	0.52	1.29	0.69	0.52	1.21	0.63	0.49	1.12
	Munich	1.08	0.52	1.60	0.95	0.52	1.47	0.90	0.52	1.42	0.77	0.52	1.29	0.73	0.52	1.25	0.68	0.52	1.20	0.38	0.52	0.90
	Berlin	1.24	0.52	1.76	0.98	0.52	1.50	0.96	0.52	1.48	0.96	0.52	1.48	0.85	0.52	1.37	0.76	0.52	1.28	-	-	-
	Dresden	1.05	0.52	1.57	0.87	0.52	1.39	0.81	0.52	1.33	0.79	0.52	1.31	0.59	0.52	1.11	0.61	0.51	1.12	-	-	-
Spain	Madrid	1.19	-	1.19	0.66	-	0.66	0.35	-	0.35	0.34	-	0.34	0.32	-	0.32	0.32	-	0.32	-	-	-
	Barcelona	1.19	-	1.19	0.66	-	0.66	0.35	-	0.35	0.34	-	0.34	0.32	-	0.32	0.32	-	0.32	-	-	-
	Valencia	1.19	-	1.19	0.66	-	0.66	0.35	-	0.35	0.34	-	0.34	0.32	-	0.32	0.32	-	0.32	-	-	-
	North & East	1.19	-	1.19	0.66	-	0.66	0.35	-	0.35	0.34	-	0.34	0.32	-	0.32	0.32	-	0.32	-	-	-
France	Lille	1.14	-	1.14	0.96	-	0.96	0.68	0.17	0.85	0.66	0.17	0.83	0.56	0.28	0.84	0.55	0.28	0.83	0.55	0.23	0.78
	Paris	1.14	-	1.14	0.96	-	0.96	0.67	0.18	0.85	0.66	0.18	0.84	0.56	0.29	0.85	0.55	0.29	0.84	0.55	0.23	0.78
	Strasbourg	1.34	-	1.34	1.17	-	1.17	0.78	0.18	0.96	0.73	0.19	0.92	-	-	-	-	-	-	-	-	-
	Marseille	1.14	-	1.14	0.96	-	0.96	0.68	0.17	0.85	0.66	0.17	0.83	0.56	0.28	0.84	0.55	0.28	0.83	0.55	0.23	0.78
	Lyon	1.14	-	1.14	0.96	-	0.96	0.66	0.17	0.83	0.65	0.17	0.82	0.55	0.29	0.84	0.53	0.29	0.82	0.55	0.23	0.78
	Toulouse	1.14	-	1.14	0.96	-	0.96	0.68	0.17	0.85	0.62	0.17	0.79	0.55	0.28	0.83	0.54	0.28	0.82	0.55	0.23	0.78
Ireland	Dublin	0.88	-	0.88	0.71	-	0.71	0.38	-	0.38	0.38	-	0.38	0.24	-	0.24	0.24	-	0.24	0.24	-	0.24
Italy	Milan	1.50	0.42	1.92	1.46	0.41	1.87	0.35	0.42	0.77	0.34	0.42	0.76	0.31	0.41	0.72	0.29	0.42	0.71	0.24	-	0.24
	Turin	1.42	0.41	1.83	1.35	0.42	1.77	0.35	0.42	0.77	0.34	0.42	0.76	0.31	0.41	0.72	0.29	0.42	0.71	0.24	-	0.24
	Genoa	1.49	0.41	1.90	1.48	0.41	1.89	0.35	0.42	0.77	0.34	0.42	0.76	0.31	0.41	0.72	0.29	0.42	0.71	0.24	-	0.24
	Rome	1.69	0.41	2.10	1.63	0.41	2.04	0.35	0.42	0.77	0.34	0.42	0.76	0.31	0.41	0.72	0.29	0.42	0.71	0.24	-	0.24
	Naples	2.09	0.42	2.51	2.04	0.41	2.45	0.35	0.42	0.77	0.34	0.42	0.76	0.31	0.41	0.72	0.29	0.42	0.71	0.24	-	0.24
Luxembourg	Luxembourg -ville	0.29	-	0.29	0.27	-	0.27	0.26	-	0.26	0.25	-	0.25	0.24	-	0.24	0.24	-	0.24	-	-	-
Netherlands	Rotterdam	1.01	0.27	1.28	0.99	0.28	1.27	0.58	0.28	0.86	0.57	0.28	0.85	0.47	0.25	0.72	0.47	0.25	0.72	0.40	0.19	0.59
Portugal	Lisbon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UK	London	0.92	-	0.92	0.79	-	0.79	0.64	-	0.64	0.63	-	0.63	0.58	-	0.58	0.58	-	0.58	0.38	-	0.38
	Leeds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Birmingham	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Source: Gas prices 1990-94, Eurostat, 1994.

Table B5.3. Energy taxes in the EU Member States

Country	Heavy fuel oil for industry (ECU per tonne) in 1994			Heavy fuel oil for electricity generation (ECU per tonne) in 1993		
	Excise tax	VAT	Total tax	Excise tax	VAT	Total tax
Austria	21.02	0	21.02	0	0	0.00
Belgium	7.99	0	7.99	17.71	0	17.71
Denmark	20.55	0	20.55	n.a.	n.a.	n.a.
Finland	21.77	0	21.77	12.57	0	12.57
France	16.75	0	16.75	21.02	0	21.02
Germany	15.10	0	15.10	27.18	0	27.18
Greece *	40.41	0	40.41	42.77	0	42.77
Ireland	5.86	0	5.86	5.47	0	5.47
Italy **	22.80	0	22.80	1.47	n.a.	1.47
Luxembourg	13.43	0	13.43	n.a.	n.a.	n.a.
Netherlands	29.30	0	29.30	28.72	0	28.72
Portugal	35.08	0	35.08	0	0	0.00
Spain	12.22	0	12.22	12.86	0	12.86
Sweden	38.12	0	38.12	14.70	0	14.70
United Kingdom	6.45	0	6.45	n.a.	n.a.	n.a.

Source: IEA 'Energy Prices and Taxes', Paris, 1995.
* Electricity for industry refers to 1993 prices.
** Natural gas for households refers to 1993 prices.

Table B5.4. Percentage breakdown of gas consumption of different end-users (1993)

Country	Industry	Residential	Others *	Total
Austria	51.5	48.0	0.6	100
Belgium	44.2	39.0	16.8	100
Denmark	37.6	38.9	23.5	100
Finland	95.5	3.0	1.5	100
France	43.7	28.6	27.7	100
Germany	40.9	41.3	17.8	100
Greece	85.7	0.0	14.3	100
Ireland	68.4	18.8	12.8	100
Italy	43.6	55.4	1.0	100
Luxembourg	63.8	36.2	0.0	100
Netherlands	36.7	34.2	29.1	100
Portugal	0.0	80.0	20.0	100
Spain	76.8	16.9	6.3	100
Sweden	64.1	17.9	17.9	100
United Kingdom	23.5	60.1	16.5	100

Source: IEA, 'Energy Balances of OECD Countries 1992–1993', Paris, 1995.
* It includes transport, agriculture, commerce and public service and non-specified.

B6. Modelling and game theory

B6.1. Further discussions of oligopoly models

This section contains further discussion of issues raised in the main text.

B6.1.1. Risk and cost factors

One possible outcome from TPA is that there is border price parity between producers. This would result in the standard oligopoly model where prices must be equal if market share is not to be lost.

However, it is conceivable that segmented markets could appear, determined by the risk preferences of consumers and also by consumer location. For example, the FSU could supply higher risk, low price gas to risk-averse users. At the same time, producers may be able to supply gas more cheaply at locations close to their borders with the EU. If transmission costs within the EU are large compared to differences in producers' costs, then markets close to EU borders could be dominated by producers close to those markets.

If segmented markets are formed due to either security of supply or geographic location, there is unlikely to be strong competition between producers. This will be partly mitigated by consumers being able to buy a mix of gas from different producers in order to match their risk preferences.

This leads to two situations:

Situation 1: a single market for gas results under TPA

Under the following three assumptions, we model the European market for gas under TPA as a Cournot oligopoly model:

(a) differences between security of supply are small implying that the risk premium is insignificant;
(b) transmission costs are low within the EC;
(c) differences in producers' costs are not large enough to induce low cost producers into a strategy of forcing out competition.

No price discrimination is possible.

The producers must all charge the same price for gas, but they supply different quantities to the market depending on their costs. As total supply to the market increases, the gas price must fall.

Pricing disparity with the oil price – if profit maximizing levels of supply imply a price which is lower than the oil price, we would expect to get an outcome in line with the standard oligopoly result. However, this appears most unlikely.

Pricing parity with the oil price – at oil price parity producers may be unwilling to increase supply to the market because of the inelastic nature of demand below price. At this 'kink point' in demand there may be no *unique* equilibrium of individual producers' output. However, while it is uncertain how much each producer would supply individually, we are able to predict the total supply to the market and the final price to consumers – a price equal to the oil price.

Relaxing the third assumption of our Hypothesis 1 (differences in producers' costs), without relaxing the other two assumptions, may result in Bertrand competition in the gas market and possible predatory pricing. For example, if the FSU were a very low cost producer compared to Norway and Algeria, then it could price its competitors out of the market. Bertrand competition would prove successful for a low cost producer if, in addition to assumptions 1 and 2:

(a) cost differentials are large and exit costs are low so that lower profit margins would be more than compensated by gaining the entire European gas market; or
(b) re-entry costs for producers are high and exit costs are low enough for the low cost producer to pursue a predatory pricing strategy.

Relaxing the three assumptions in situation 1 results in our second scenario, situation 2.

Situation 2: TPA results in the formation of segmented markets

In situation 2, we assume that producers are able to charge different prices because they serve different markets. In particular, the markets that are formed under TPA are characterized by geographic location and by risk preferences. Norway, as a low security risk producer, is able to charge a higher price for its gas. The FSU and Algeria, on the other hand, sell more cheaply to risk-neutral and less risk-averse gas users. A likely outcome in this scenario is that consumers buy a mix of gas to suit their risk preferences.

It is possible that a unique equilibrium in price and quantities will exist if the costs of suppliers are very different. Specifically, if one supplier has much higher production costs than the other, then the lower cost supplier may find it economic to undercut the other by pricing just below the others' marginal cost of supply so capturing the entire market of risk-neutral gas users.

The outcome of this scenario is that all producers continue to supply the gas market, but target their supply at different segments. They therefore charge different prices, and supply different classes of consumer.

B6.2. A Hotelling approach to gas pricing

Hotelling's rule[43] is a pricing principle which aims to determine the optimal consumption of non-renewable resources. The rule states that for the time path of extraction of a non-renewable resource to be optimal,[44] the net price (selling price less marginal extraction cost) of a unit of resource must rise at a rate equal to the interest rate. It relies on there being perfect competition in the market for the non-renewable resource.

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[43] 'The economics of exhaustible resources', H. Hotelling, *Journal of Political Economy*, Vol. 39, 1931.

[44] By optimal we mean welfare maximizing.

The reasoning behind the rule is as follows. If it is assumed that a producer sets prices in each period to maximize the present value of profits, then by definition, this yields a profit maximizing level of production in every period. The only condition under which the producer will not want to alter this level of production is when the *marginal* present value of profit is constant in every period. For this to happen, marginal profit must rise with the discount (interest) rate. Since marginal profit is simply marginal revenue less the marginal cost of the resource, and price equals marginal revenue in a competitive market, this yields Hotelling's rule.

The last step in the reasoning shows why for Hotelling's rule to hold, it is necessary for there to be a competitive producer market for the resource. If, for example, there was a single profit maximizing producer, then Hotelling's rule must be modified so that discounted marginal profit rises with the interest rate – since price is no longer equal to marginal revenue.

Two major assumptions that have been both explicitly and implicitly made in Hotelling's rule are therefore:

(a) that the resource is non-renewable, and that the quantity of resource available is known;
(b) that the producer market is perfectly competitive (i.e. that producers are price-takers).

In application to gas, both of these assumptions are violated. The amount of resources is unknown, as the market is far from perfectly competitive.

In addition to the first assumption, an optimal pricing problem also arises because the increase in the cost of energy must be taken into account, as gas is eventually replaced by a more expensive resource. Optimal pricing includes the costs imposed on future generations through higher consumption today. These costs can be modelled, but with considerable difficulty due to the uncertainty of when gas reserves will be finally depleted and the cost of a replacement fuel.

The market imperfections in the European gas market add further problems in using Hotelling's rule to predict future gas prices. Pricing policies will depend on many factors. These include their estimates of their own and others' gas reserves, the price of competing fuels such as oil, demand for energy, and political considerations. In particular, the high reserve to production ratios among key exporters mean that consideration of pricing on the basis of a finite resource base is unlikely to figure in practical decision making processes.

We conclude, therefore, that although Hotelling's rule provides a useful insight into the optimal pricing of resources such as gas, it does not provide a robust methodology for predicting future prices in the European gas market.

B6.3. Game theory concepts relevant in modelling the European natural gas market

Game theory provides a general framework for analysing the interaction of decision making agents. It has applications in economics, biology, politics, and social theory. For our purposes, game theory allows us to analyse the strategies of producers and transmission companies in the European gas market.

Game theory is particularly relevant to the European gas market because the number of major participants is low. When there are few player in a market, the behaviour of each player has a greater impact on the market as a whole. Under such circumstances the opportunity for gaming and collusion – either tacit or overt – increases. The European gas market currently has few major producers, and the transmission companies are monopolies in the areas they serve. The market is also characterized by long-term contracts between producers and transmission companies, and the final market price is strongly correlated with oil and coal prices. Such a structure and final price suggests that gaming may presently be taking place within the market. This appendix outlines the theory we have used in modelling the behaviour of producers and transmission companies in the current situation and under the introduction of TPA.

The appendix is arranged in the following way. In Section B6.3.1 we define the basic concepts in game theory. In Section B6.3.2 we describe the results we might expect as an outcome from a game. We consider the importance of a specific game (the Prisoners' Dilemma) to oligopoly theory in Section B6.3.3. In Section B6.3.4 we return to general games and consider what result might occur when more than one solution to a game is possible. Section B6.3.5 introduces the possibility of uncertainty in players' information.

In Sections B6.3.7 to B6.3.10 we consider what happens in repeated games and revisit the Prisoners' Dilemma to see how tacit co-operation might be brought about in an oligopoly market. Section B6.3.11 then looks at some of the major criticisms that are made about the results derived from repeating the Prisoners' Dilemma. Section B6.3.12 indicates how the model can be improved to take into account these criticisms.

Finally, in Sections B6.3.13 to B6.3.14, we consider the theory of co-operative games and assume that binding contracts are possible. We outline Nash bargaining theory and suggest that this is a useful framework for analysing bargaining for profits between firms.

B6.3.1.Defining a game in economics

A game in economics is a competitive situation where several agents make decisions, and then receive a pay-off resulting from their decisions. An agent's choice at each decision point is determined by the final pay-off which it expects to receive. The assumed objective of each agent is that they want to maximize their pay-offs from the game. The possibility that actions by one player affect the pay-offs of other players results in the formation of players' strategies.

The assumption of pay-off maximization causes some difficulties in using game theory to model real-life applications. One particular problem is that in real-life games players act differently given identical situations. This arises because players have different valuations of seemingly similar pay-offs. For example, it would be wrong to suggest that any agent playing a game which had monetary pay-offs would necessarily maximize the revenue accruing to him. Some players would take other considerations into account such as benefit or loss accruing to others and time and effort of the player involved.

In modelling economic behaviour of firms, however, there is usually less modelling difficulty since it is generally assumed that they will maximize expected profits. There are instances where this may not be the case, but careful evaluation of the real-life situation should allow identification of where these instances might occur. Usually, where profits do not appear to be maximized in the short run, they are maximized in the long run. For example, a firm may make an expenditure to reduce pollution risk. Although this expenditure reduces profit in the short run, it also reduces the long-run risk of pollution which the firm could be held accountable for in the future.

Whilst a firm will pursue the maximization of expected profits, it may turn out that the firm has failed to maximize actual profits. This may be due to the unpredictability of the future or having insufficient information to analyse the situation adequately. Uncertainty in an economic situation gives rise to problems of 'incomplete' and 'imperfect' information. These are issues which we discuss in a later section.

For the rest of this appendix, and in the main report we shall assume that all agents maximize their monetary pay-off.

B6.3.2. The expected result of a game

We describe in this section what we might expect to see as an outcome from a game. In particular, we want to be able to suggest what players might do, given the rules and circumstances they find themselves in. If each player wants to maximize his pay-off, given the information available to him, what will his strategy be

When each and every player's strategy in the game maximizes his pay-off, given the strategies of the other players, the combined set of strategies is known as a Nash equilibrium. A Nash equilibrium implies that no *single* player should want to deviate from his strategy, since it is the optimal strategy given the strategies of the other players. This is not to say that such an equilibrium is unique, or that it is the 'best' solution available to all the players; it merely means that no maximizing player will unilaterally deviate from it. The Nash equilibrium is a useful concept because it means that the players' strategies are unilaterally stable. It does not, however, say anything about how the players reach such an equilibrium.

B6.3.3. Importance of the Prisoners' Dilemma in oligopoly theory

In the previous sections we have described what a game is, what players' objectives are, and the relationship between players' optimal strategies – characterized by the Nash equilibrium. In this section we digress from the theory and focus on one particularly useful game.

An important pay-off structure in oligopoly theory is that characterized by the Prisoners' Dilemma. The game was originally suggested in terms of two prisoners' dilemma over whether to confess or deny a crime, and essentially represents a co-ordination problem between selfish individuals. Economists use the Prisoners' Dilemma pay-off structure to describe the game played between oligopolists in a market.

The oligopolists' problem was first examined by Cournot. He considered duopolist producers selling an identical product. The producers must sell at the same price, otherwise the cheaper producer would make all the sales. Cournot's concept is that although the duopolists do not compete in prices, they do compete in quantities. The more each producer wants to sell, the lower the market price must be to sell the increased quantity. Since there is not enough room in the market for both companies to extract monopoly rents, the companies must decide on how much to supply to the market. For each specific quantity sold by one producer, there exists a unique profit maximizing quantity that the other producer should sell. In equilibrium, each producer's output will maximize its profits, given the output of the other producer. Such an equilibrium is a Nash equilibrium.

Even though this equilibrium level of output maximizes each of the producer's profits individually, it is not the 'best' solution available to them. Both producers could make higher profits by agreeing to a restricted total output (at the monopoly level) and sharing the profits in some way. However, this restricted level of output is not an equilibrium because at the monopoly level of output one producer could cheat on the other by increasing its output and thereby increasing its market share. Thus, even though both producers would be better off by joint maximization, they are unable to trust the other party not to increase sales unless they can sign a binding agreement.

B6.3.4. Games with more than one solution

In the Prisoners' Dilemma game we describe above, there is a unique Nash equilibrium solution. When there are more than one set of strategies which are optimal – multiple Nash equilibrium – the modeller is faced with a choice of which equilibrium to choose as the most likely outcome of the game. The modeller must therefore find some way to reject some of the Nash equilibria. In this section we consider some of the refinements that can be made to multiple solutions.

One particular criticism of some Nash equilibria is that they implicitly contain 'non-credible threats'. This occurs when a player is induced into playing a particular strategy by a threat from another player. It is possible, however, that this threat could also worsen the pay-off of the threatening player. In this case, if the player's bluff was called, then it would be rational for him not to execute the threat. The reason why this type of behaviour is admissible in a Nash equilibrium is that, in equilibrium, the player is never required to carry out the incredible threat. Thus, the particular Nash equilibrium is brought about by a player's threat of sub-optimal play away from the equilibrium.

Many economists believe that Nash equilibria involving incredible threats are 'bad' because a threatened player would not be duped into it. This dissatisfaction with the general set of Nash equilibria has lead game theorists to attempt to refine the set of Nash equilibria to only 'good' equilibria, and preferably a unique equilibrium.

Perhaps the most compelling refinement of Nash equilibria is the concept of 'Subgame Perfect Equilibrium'. The Subgame Perfect Equilibrium is found by working backwards from the final pay-offs to the starting move. Each player considers the last decision that he needs to make in the game. If each player knows what pay-off he will get at this last move, then simple maximization indicates what option to take. Each player then considers his penultimate decision. Since his last move, and every other player's last move in the game is already decided from the previous calculation, then simple maximization will tell each player what to play at this penultimate decision point. This process can be repeated backwards to the first decision point. The final result is optimal play for each player from the first decision point to the last, giving each player an overall optimal strategy.

The advantage of a subgame perfect equilibrium is that it does not admit any incredible threats since players use an optimal strategy at every stage of the game, whether in equilibrium or not. Thus, the players' strategies constitute a Nash equilibrium not just for the entire game, but also for every decision point within the game (subgames). However, there are also critiques of subgame perfection. The two major difficulties are, first, the reliance on backwards induction for a solution, and second, when imperfect information is introduced. The former criticism is made because of frequently observed myopia – or 'bounded rationality' – of players (see

Section B6.3.11), and the latter requires a detailed knowledge of the beliefs of the players in the game.

In our analysis of the European gas market, we take a pragmatic approach to Nash equilibria refinements. In particular we follow the suggestion of Binmore (1992) in taking into account all the circumstances of the game before deciding which equilibrium is appropriate for given situations. We do not therefore rule out any equilibrium until analysis suggests that the equilibrium is unrealistic.

B6.3.5. Imperfect information

Up to now we have considered games in which the rules and the pay-offs are common knowledge to all the players. In a situation like the European gas market it is clear that agents will hold important private information which is unavailable to others. This private information includes costs and estimates of gas reserves, which are vital for agents to form pricing policies under any market conditions. In this section, we examine the scope for game theory to deal with such information 'asymmetries'.

In game theory literature, a game is said to have 'imperfect information' when a player is unsure as to what happened in previous play by other players. Game theory is structured so that each player makes his move sequentially. Imperfect information therefore allows us to model situations where players move simultaneously. This is achieved by assuming the player which moves second does not know the action of the first player. Thus, the second player is unable to distinguish between outcomes within any single information set.

Uncertainties about, say, producers costs, can be modelled in this way – by assuming that at the start of a game, a producer is endowed with a certain cost function. The producer itself knows its own cost, but it is not observed by other players. The other players may have some approximate idea of the producer's costs but must infer anything more detailed through the actions of the producer. Such an information asymmetry may lead the producer into strategies which disguise its cost function.

Inference of costs by the other players can be made by analysing the motives of the producer, and by analysing play in the game before that stage. Observations allow the other players to form beliefs about the information which they do not currently know. However, in order to do this, they must also make important assumptions about how other players will behave.

B6.3.6. Risk aversion

Risk aversion is not given a great deal of coverage in game theory, but needs to be considered in many modelling contexts. Players are usually assumed to maximize expected pay-offs, thereby making them risk-neutral. In practice, most players are risk-averse and therefore require a premium for taking risks. This needs to be built into players' pay-off functions in order to model the situation accurately.

B6.3.7. Repeated games

In real life, economic situations are repeated more than once. For example, competing duopolists have the opportunity to change prices over time, and two firms in a bilateral agreement may have to renegotiate a contract when the original contract expires.

Game theory allows us to model such situations by simply extending the original game for the number of times it is repeated in practice. The final game to be analysed becomes a 'supergame' which is simply a repetition of the original game. This framework allows the game theorist to model repeated games between players, and is clearly a very useful tool in modelling the European gas market.

To model a game accurately over time it is necessary to introduce a discount rate which is applied progressively to pay-offs throughout the game. This means that the present value of the pay-off from later games is lower than previous games. The change in pay-offs due to the discount rate can mean that there are different optimal strategies in the repeated game and the one-off game. We consider in particular what happens to the duopolist – Prisoners' Dilemma – game if played more than once.

B6.3.8. The Prisoners' Dilemma as a repeated game

In Section B6.3.3 we introduced the 'one-shot' Prisoners' Dilemma and described how the pay-offs could be viewed as those faced by competing duopolists. The result can be generalized to the oligopoly case.

The conclusion in Section B6.3.3 was that the duopolists would produce at a non-co-operative level. Although they would like jointly to maximize profits by restricting output to the monopoly level, they were unable to commit to such a strategy for fear that one of them would cheat on the arrangement by increasing output. This section reviews this conclusion in the circumstance where the duopolists compete over time, since co-operation in the short term could mean higher profits in the future.

B6.3.9. Repeating the game a finite number of times

A first attempt at modelling the repeated game is by considering the Prisoners' Dilemma game repeated a finite number of times. A vitally important assumption is that both players know how many times the game is repeated before it ends. In this circumstance the players could solve for their optimal strategy by considering the last stage first. In the last game, players have nothing to lose by choosing the non co-operative strategy – since no actions take place after this point they choose their strategy in accordance to the one-shot game. *ac ard induction* suggests that in the penultimate game, players will also not co-operate since they know that no co-operation will occur in the last game. This reasoning can be employed backwards to show that rational players would not co-operate at any stage in a finitely repeated Prisoners' Dilemma. Hence, there is a theoretical result in game theory that players do not co-operate if the Prisoners' Dilemma is repeated only a finite number of times, and both players know how many times the game will be repeated. The result is both a Nash equilibrium and a Subgame Perfect Equilibrium (as described in Section B6.3.4). The equilibrium has the property that at every stage each player is playing his optimal strategy.

B6.3.10. An infinite or uncertain horizon in the Prisoners' Dilemma

The co-operative dilemma facing the duopolists can be resolved in an infinitely repeated setting. In contrast to the one-period game and the finitely repeated game, where it always pays to increase output to the non-co-operative level, many equilibria for the infinitely repeated game exist. If one producer, for instance, decides to always restrict output, then the other producer will always do best by producing at the high level of output. But if a producer decides to restrict output until the other increases its output and never co-operates again, both producers could do best by co-operating at every stage. Depending on the discount rates of the players, it is feasible that the players will co-operate at every repetition of the game.

The crucial difference between the infinite horizon game and the finite horizon game is that the duopolists are always able to punish non-co-operation in the infinite horizon game because players are unsure when the game will end. Thus, under certain assumptions about the market structure, we can see why oligopolists may decide to restrict output to the monopoly level. This reasoning also applies when the end point of the game is unknown, i.e. players do not know how many rounds of the game there may be. This appears to apply closely to the European gas industry.

B6.3.11. Criticism of the Prisoners' Dilemma as a model of an oligopoly market

The two theoretical outcomes described above under finite and infinite repetition of the Prisoners' Dilemma can both be criticized as models of an oligopoly market. Several game theorists have expressed some doubts about the validity of the finite game Nash equilibrium of non-co-operation. For example, even if the game lasted for a great number of periods – but still ended at some point – backwards induction still indicates that rational players would not co-operate. If we do not believe in such an outcome in real life then further information needs to be built into the game to give it more realism. It is our view that such backwards induction does not fully describe the situation faced by producers in the European gas market.

To model the intuitive idea that oligopolists may tacitly co-operate at a restricted level of output, we introduced the concept of an infinite horizon. Under this assumption, and the assumption that players have perfect information about pay-offs and market structure, we could conclude that co-operation between producers would take place. However, this latter assumption is extremely restrictive and highly unrealistic. It is then natural to ask: what are the conditions that would make co-operation possible In the following section we describe some of the important conditions that affect the potential co-operation of producers in a market.

B6.3.12. Refinements in the repeated Prisoners' Dilemma

In this section we conclude our analysis of the Prisoners' Dilemma by examining the conditions under which the co-operation between duopolists might break down. The following market characteristics could cause producers in the European gas market to end tacit collusion and engage in non-co-operative behaviour:

(a) *The pay-off structure*. The relative sizes of the pay-offs for each strategy determine both what the players wish to do themselves and what they expect their opponents to do. For example, there is much less incentive to undercut a competitor if this yields little benefit than if it is very profitable. The pay-off from defecting from the restricted output is determined by the costs of the companies and the shape of the demand curve.

(b) *The 'noise level*. This refers to the extent to which it is possible to infer from observations what strategy was chosen by the opposition. A producer can only confidently 'punish' non-co-operation by another producer if it knows for sure that the other producer has defected. If it is difficult to observe whether a producer has changed its strategy, and not simply given a discount to a customer for particular circumstances, tacit collusion will be hard to maintain.

(c) *Predictability of the future.* Uncertainty about the future may cause a producer to break co-operation at a high price level. The producer may believe that the chances of the market structure remaining the same over time are very small. In this case it may decide to increase its profits in the short run by increasing output and lowering price.
(d) *The discount rates of the players.* If one producer values earnings in the near future more than those in the distant future and the other is indifferent, the former may be tempted to undercut the latter and test the resolution of the latter to punish such behaviour.

We can conclude from our survey of non-co-operative game theory that there are instances where optimal oligopoly behaviour results in tacit collusion. Under these circumstances, the producers will restrict output to the market and price at the monopoly level. We have shown that there are also conditions under which tacit collusion is made very difficult, to the point where players will eventually decide to price at the non-co-operative level. The exact circumstances in the market will determine whether tacit collusion or non-co-operation will take place.

B6.3.13. Co-operative game theory

This section stands apart from other sections in this appendix in that we describe the theory of games where binding commitments can be made. Such a theory is motivated by the fact that many non-co-operative games lead to both multiple equilibrium and jointly 'undesirable' outcomes.

Co-operative game theory is characterized by players bargaining over shares in a total pay-off. All the players attempt to get a higher share as possible, but are clearly restricted by the total amount to be shared. For example, the one-shot Prisoners' Dilemma could be interpreted in a co-operative context if binding agreements were possible. In this case, the players would agree to commit to the joint-maximizing (monopoly) position but would be faced with a different dilemma – how to split the profits [45] A natural outcome might be to split it 50-50, but this is not the only division that is possible. Co-operative game theory formalizes the bargaining possibilities of each of the players.

A bargaining set is the set of all feasible outcomes of the game. For example, if two players are bargaining for amounts x and y from a total of 10, the bargaining set will include all possibilities such that the two amounts add to no more than 10, and with no player having less than 0. For game theory analysis, some basic technical restrictions are put on the bargaining set. These are set out below:

(a) The bargaining set is convex. This means that players are not restricted from sharing a given pay-off in any way they choose.
(b) The set is bounded above and is closed. This is a technical requirement which says that the total pay-off is a finite amount and that all of the pay-off can be shared.
(c) Free disposal is possible. A second technical requirement which means that the players are able (if willing to do so) to give money away.

Given such a bargaining set, the players will naturally wish to get an optimal agreement for themselves. In particular, players will not agree to an allocation which can be Pareto

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[45] We assume that one producer has a traditionally high share in the market and so will have higher profits if both producers charge the same price.

improved.[46] The players will therefore choose allocations on the frontier of the bargaining set, i.e. there will be nothing left over after shares have been taken. In the example given above, this means that the players' shares will always add to £10.

B6.3.14. Nash bargaining solution

Nash defined a bargaining problem to be a situation where there is a bargaining set, and where this set includes a point of disagreement. Players receive the disagreement pay-off if negotiations break down. In some cases this might be zero. In the example of sharing £10, we might assume a disagreement point as an allocation of £3 for each player.

Nash suggested that the shares which each player could negotiate in such instances depended on the:

(a) shape of the bargaining set,
(b) the disagreement point, and
(c) the relative bargaining powers of the players.

Clearly, no player would bargain for less than what he could achieve at the disagreement point. At the same time, both players want to be on the frontier of the bargaining set. However, this does not define a unique bargaining solution. Nash suggested four axioms (assumptions) which, taken together, describe a unique solution – known as the *Nash Bargaining Solution*. The axioms are:

(a) Invariance to equivalent utility representations. This means that the final outcome should not depend on how players' utility scales are calibrated.
(b) Symmetry. In symmetric situations, both players should receive the same pay-offs.
(c) Independence of irrelevant alternatives. If the players sometimes agree on the set of pay-offs X when Y is feasible, then they never agree on Y when X is feasible.
(d) Pareto efficiency. No pay-off would result where all players could be made better off with a different feasible pay-off.

Under these conditions, Nash showed that a unique equilibrium existed for n players in a bargaining game. Defining x_i as the pay-off to player i and d_i as the disagreement pay-off to player i, the Nash bargaining solution to the x_i's is the solution to:

Maximize $(x_1-d_1)(x_2-d_2)....(x_n-d_n)$

subject to all x_i being both feasible (in the bargaining set) and greater than the disagreement pay-offs (i.e. $x_i>d_i$ for all players i).

Nash generalized the solution to include non-symmetric bargaining powers. For example, in a two-player game the bargaining powers of the two players could be described by numbers a and b, with a+b=1, a>0, b>0. If a player has a bargaining power of 1, it means that the player has all the bargaining power and would get the highest pay-off possible. If both players have a bargaining power of 0.5, then the bargaining power is symmetric and they each receive the same pay-off.

[46] A Pareto improvement is possible if an alternative allocation makes all players better off at the same time.

In the context of two players with different bargaining powers, the Nash bargaining pay-offs are given by:

Maximize $(x_1\text{-}d_1)^a(x_2\text{-}d_2)^b$

subject to all x_i being both feasible (in the bargaining set) and greater than the disagreement pay-offs (i.e. x_i d_i for all players *i*).

B6.3.15. Summary

To summarize, the Nash Bargaining Solution is based on four important assumptions. The assumptions of Pareto efficiency, invariance to utility, scale and independence are plausible. The assumption of bargaining power requires a further analysis of what determines bargaining power. This must be decided through a wider consideration of the positions of the players in the bargaining problem. More information is thus needed before estimates of bargaining power can be given. Although the Nash Bargaining Solution depends on such estimates, it is still useful as a framework for analysing bargaining between firms.

B7. Numerical sensitivities

Table B7.1. Base case

Summary of value chain

	PG	Industry
Value of gas	4.20	3.50
Cost of producers	2.73	2.73
Cost of transmission	0.20	0.20
Rent in trans	0.10	0.10
Other rent	1.17	0.47

Other assumptions

	PG	Industry
Elasticity	-0.5	-0.6
Volume affected (bcm pa)	50	25

Rent allocation		**Scenario 1**		**Scenario 2**
Present situation	Barg/Pow	% of rent	Barg/Pow	% of rent
Producers	1	83%	1	83%
Transmission co	0.2	17%	0.2	17%
Consumers	0	0%	0	0%
TPA				
Producers	1	91%	1	71%
Transmission co	0	0%	0	0%
Consumers	0.1	9%	0.4	29%

Table B7.2. Base case: changes in producer revenues

			Scenario 1		Scenario 2	
Description	**Sector**	**Units**	**nTPA**	**TPA**	**nTPA**	**TPA**
Change in price	Industry	US$/MMBtu	(0.04)	(0.05)	(0.13)	(0.16)
	Power gen	US$/MMBtu	(0.11)	(0.12)	(0.33)	(0.36)
Change in volume	Industry	bcm pa	0.18	0.22	0.58	0.70
	Power gen	bcm pa	0.63	0.69	1.99	2.16
Total volume		bcm pa	0.82	0.91	2.57	2.86
Change in border price	Industry	US$/MMBtu	0.04	0.13	(0.06)	0.02
	Power gen	US$/MMBtu	0.09	0.18	(0.14)	(0.07)
Consumer saving (on present vol)		US$m pa	255.5	282.7	802.9	888.6
Total change in producer revenue		US$m pa	332.1	621.2	19.9	281.6

Table B7.3. Base case: elasticities effect on volume

	Scenario 1		Scenario 2		
% rent to consumers					
	Ntpa	tpa	Ntpa	tpa	
Industry	9.1%	9.1%	28.6%	28.6%	
Power generation	9.1%	9.1%	28.6%	28.6%	
Change in prices					
	Ntpa	tpa	Ntpa	tpa	
Industry	(0.04)	(0.05)	(0.13)	(0.16)	
Power generation	(0.11)	(0.12)	(0.33)	(0.36)	
Present final price					
	Ntpa	tpa	Ntpa	tpa	
Industry	3.5	3.5	3.5	3.5	
Power generation	4.2	4.2	4.2	4.2	
New final price					
	Ntpa	tpa	Ntpa	tpa	
Industry	3.46	3.45	3.37	3.34	
Power generation	4.09	4.08	3.87	3.84	
Percentage change in price					
	Ntpa	tpa	Ntpa	tpa	
Industry	-1.2%	-1.5%	-3.8%	-4.7%	
Power generation	-2.5%	-2.7%	-8.0%	-8.6%	
Percentage change in volume					
	Ntpa	tpa	Ntpa	tpa	Elasticity
Industry	0.7%	0.9%	2.3%	2.8%	-0.6
Power generation	1.3%	1.4%	4.0%	4.3%	-0.5
Present volumes					
	Ntpa	tpa	Ntpa	tpa	
Industry	25	25	25	25	
Power generation	50	50	50	50	
Change in volumes					
	Ntpa	tpa	Ntpa	tpa	
Industry	**0.2**	**0.2**	**0.6**	**0.7**	
Power generation	**0.6**	**0.7**	**2.0**	**2.2**	
New volumes					
	Ntpa	tpa	Ntpa	tpa	
Industry	25.2	25.2	25.6	25.7	
Power generation	50.6	50.7	52.0	52.2	

Table B7.4. Base case: border prices

Cost of producers				
	Ntpa	tpa	Ntpa	tpa
Industry	2.7	2.7	2.7	2.7
Power generation	2.7	2.7	2.7	2.7
Present rents				
	Ntpa	tpa	Ntpa	tpa
Industry	0.5	0.5	0.5	0.5
Power generation	1.2	1.2	1.2	1.2
Present % rent to producers				
	Ntpa	tpa	Ntpa	tpa
Industry	0.8	0.8	0.8	0.8
Power generation	0.8	0.8	0.8	0.8
Present border price				
	Ntpa	tpa	Ntpa	tpa
Industry	3.1	3.1	3.1	3.1
Power generation	3.7	3.7	3.7	3.7
New % rent to producers				
	Ntpa	tpa	Ntpa	tpa
Industry	0.9	0.9	0.7	0.7
Power generation	0.9	0.9	0.7	0.7
Efficiency under TPA and nTPA				
	Ntpa	tpa	Ntpa	tpa
Industry	0.0	0.1	0.0	0.1
Power generation	0.0	0.1	0.0	0.1
Rents under TPA and nTPA				
	Ntpa	tpa	Ntpa	tpa
Industry	0.5	0.6	0.5	0.6
Power generation	1.2	1.3	1.2	1.3
New border price				
	Ntpa	tpa	Ntpa	tpa
Industry	3.16	3.25	3.07	3.14
Power generation	3.79	3.88	3.57	3.64
Change in border price				
	Ntpa	tpa	Ntpa	tpa
Industry	0.04	0.13	(0.06)	0.02
Power generation	0.09	0.18	(0.14)	(0.07)

Table B7.5. Base case: consumer saving

	Scenario 1		Scenario 2	
Present expenditure				
Industry	88	88	88	88
Power generation	210	210	210	210
New exp at old volumes				
Industry	86	86	84	83
Power generation	205	204	193	192
Difference = $m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	43	52	134	163
Power generation	213	231	669	726

Table B7.6. Base case: change in producer revenue

Present revenue=US$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	3122	3122	3122	3122
Power generation	7410	7410	7410	7410
New revenue=US$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	3180	3277	3136	3225
Power generation	7683	7876	7415	7589
Change in revenue=US$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	59	155	15	103
Power generation	273	466	5	179
	332	621	20	282

Table B7.7. Lower gas value

Summary of value chain

	PG	Industry
Value of gas	3.50	3.10
Cost of producers	2.73	2.73
Cost of transmission	0.20	0.20
Rent in transmission	0.10	0.10
Other rent	0.47	0.07

Other assumptions

	PG	Industry
Elasticity	-0.5	-0.6
Volume affected (bcm pa)	50	25

Rent allocation	**Scenario 1**		**Scenario 2**	
Present situation	Barg/Pow	% of rent	Barg/Pow	% of rent
Producers	1	83%	1	83%
Transmission company	0.2	17%	0.2	17%
Consumers	0	0%	0	0%
TPA				
Producers	1	91%	1	71%
Transmission company	0	0%	0	0%
Consumers	0.1	9%	0.4	29%

Table B7.8. Lower gas value: changes in producer revenue

			Scenario 1		Scenario 2	
Description	**Sector**	**Units**	**nTPA**	**TPA**	**nTPA**	**TPA**
Change in price	Industry	US$/MMBtu	(0.01)	(0.02)	(0.02)	(0.05)
	Power generation	US$/MMBtu	(0.04)	(0.05)	(0.13)	(0.16)
Change in volume	Industry	bcm pa	0.03	0.07	0.10	0.24
	Power generation	bcm pa	0.31	0.37	0.96	1.16
Total volume		bcm pa	0.34	0.44	1.06	1.40
Change in border price	Industry	US$/MMBtu	0.01	0.10	(0.01)	0.06
	Power generation	US$/MMBtu	0.04	0.13	(0.06)	0.02
Consumer saving (on present vol)		US$m pa	91.8	119.1	288.6	374.3
Total change in producer revenue		US$m pa	118.5	406.0	8.1	266.8

Table B7.9. Lower gas value: elasticities effect on volume

	Scenario 1		Scenario 2		
% rent to consumers					
	Ntpa	tpa	Ntpa	tpa	
Industry	9.1%	9.1%	28.6%	28.6%	
Power generation	9.1%	9.1%	28.6%	28.6%	
Change in prices					
	Ntpa	tpa	Ntpa	tpa	
Industry	(0.01)	(0.02)	(0.02)	(0.05)	
Power generation	(0.04)	(0.05)	(0.13)	(0.16)	
Present final price	Ntpa	tpa	Ntpa	tpa	
Industry	3.1	3.1	3.1	3.1	
Power generation	3.5	3.5	3.5	3.5	
New final price	Ntpa	tpa	Ntpa	tpa	
Industry	3.09	3.08	3.08	3.05	
Power generation	3.46	3.45	3.37	3.34	
Percentage change in price					
	Ntpa	tpa	Ntpa	tpa	
Industry	-0.2%	-0.5%	-0.6%	-1.6%	
Power generation	-1.2%	-1.5%	-3.8%	-4.7%	
Percentage change in volume					
	Ntpa	tpa	Ntpa	tpa	Elasticity
Industry	0.1%	0.3%	0.4%	0.9%	-0.6
Power generation	0.6%	0.7%	1.9%	2.3%	-0.5
Present volumes	Ntpa	tpa	Ntpa	tpa	
Industry	25	25	25	25	
Power generation	50	50	50	50	
Change in volumes					
	Ntpa	tpa	Ntpa	tpa	
Industry	**0.0**	**0.1**	**0.1**	**0.2**	
Power generation	**0.3**	**0.4**	**1.0**	**1.2**	
New volumes					
	Ntpa	tpa	Ntpa	tpa	
Industry	25.0	25.1	25.1	25.2	
Power generation	50.3	50.4	51.0	51.2	

Table B7.10. Lower gas value: border prices

Cost of producers				
	Ntpa	tpa	Ntpa	tpa
Industry	2.7	2.7	2.7	2.7
Power generation	2.7	2.7	2.7	2.7
Present rents				
	Ntpa	tpa	Ntpa	tpa
Industry	0.1	0.1	0.1	0.1
Power generation	0.5	0.5	0.5	0.5
Present % rent to producers				
	Ntpa	tpa	Ntpa	tpa
Industry	0.8	0.8	0.8	0.8
Power generation	0.8	0.8	0.8	0.8
Present border price				
	Ntpa	tpa	Ntpa	tpa
Industry	2.8	2.8	2.8	2.8
Power generation	3.1	3.1	3.1	3.1
New % rent to producers				
	Ntpa	tpa	Ntpa	tpa
Industry	0.9	0.9	0.7	0.7
Power generation	0.9	0.9	0.7	0.7
Efficiency under TPA and nTPA				
	Ntpa	tpa	Ntpa	tpa
Industry	0.0	0.1	0.0	0.1
Power generation	0.0	0.1	0.0	0.1
Rents under TPA and nTPA				
	Ntpa	tpa	Ntpa	tpa
Industry	0.1	0.2	0.1	0.2
Power generation	0.5	0.6	0.5	0.6
New border price				
	Ntpa	tpa	Ntpa	tpa
Industry	2.79	2.88	2.78	2.85
Power generation	3.16	3.25	3.07	3.14
Change in border price				
	Ntpa	tpa	Ntpa	tpa
Industry	0.01	0.10	(0.01)	0.06
Power generation	0.04	0.13	(0.06)	0.02

Table B7.11. Lower gas value: consumer saving

	Scenario 1		Scenario 2	
Present expenditure				
Industry	78	78	78	78
Power generation	175	175	175	175
New exp at old volumes				
Industry	77	77	77	76
Power generation	173	172	168	167
Difference = US$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	6	15	20	49
Power generation	85	104	269	326

Table B7.12. Lower gas value: change in producer revenue

Present revenue=US$USm pa				
	Ntpa	tpa	Ntpa	tpa
Industry	2788	2788	2788	2788
Power generation	6243	6243	6243	6243
New revenue=$USm pa				
	Ntpa	tpa	Ntpa	tpa
Industry	2797	2893	2791	2878
Power generation	6353	6544	6249	6420
Change in revenue=$USm pa				
	Ntpa	tpa	Ntpa	tpa
Industry	9	105	2	90
Power generation	110	301	6	177
	118	406	8	267

Table B7.13. More competition

	Power generation	Industry
Value of gas	4.20	3.50
Cost of producers	2.73	2.73
Cost of transmission	0.20	0.20
Rent in transmission	0.10	0.10
Other rent	1.17	0.47

Other assumptions

	Power generation	Industry
Elasticity	-0.5	-0.6
Volume affected (bcm pa)	50	25

Rent allocation	**Scenario 1**		**Scenario 2**	
Present situation	Barg/Pow	% of rent	Barg/Pow	% of rent
Producers	1	83%	1	83%
Transmission company	0.2	17%	0.2	17%
Consumers	0	0%	0	0%
TPA				
Producers	1	71%	1	56%
Transmission company	0	0%	0	0%
Consumers	0.4	29%	0.8	44%

Table B7.14. More competition: changes in producer revenues

			Scenario 1		**Scenario 2**	
Description	**Sector**	**Units**	**nTPA**	**TPA**	**nTPA**	**TPA**
Change in price	Industry	US$/MMBtu	(0.13)	(0.16)	(0.21)	(0.25)
	Power generation	US$/MMBtu	(0.33)	(0.36)	(0.52)	(0.56)
Change in volume	Industry	bcm pa	0.58	0.70	0.90	1.09
	Power gen	bcm pa	1.99	2.16	3.10	3.36
Total volume		bcm pa	2.57	2.86	3.99	4.45
Change in border price	Industry	US$/MMBtu	(0.06)	0.02	(0.13)	(0.08)
	Power generation	US$/MMBtu	(0.14)	(0.07)	(0.33)	(0.27)
Consumer saving (on present vol)		US$m pa	802.9	888.6	1,248.9	1,382.2
Total change in producer revenue		US$m pa	19.9	281.6	(255.0)	(19.9)

Table B7.15. More competition: elasticities effect on volume

	Scenario 1		Scenario 2		
% rent to consumers					
	Ntpa	tpa	Ntpa	tpa	
Industry	28.6%	28.6%	44.4%	44.4%	
Power generation	28.6%	28.6%	44.4%	44.4%	
Change in prices					
	Ntpa	tpa	Ntpa	tpa	
Industry	(0.13)	(0.16)	(0.21)	(0.25)	
Power generation	(0.33)	(0.36)	(0.52)	(0.56)	
Present final price	Ntpa	tpa	Ntpa	tpa	
Industry	3.5	3.5	3.5	3.5	
Power generation	4.2	4.2	4.2	4.2	
New final price	Ntpa	tpa	Ntpa	tpa	
Industry	3.37	3.34	3.29	3.25	
Power generation	3.87	3.84	3.68	3.64	
Percentage change in price					
	Ntpa	tpa	Ntpa	tpa	
Industry	-3.8%	-4.7%	-6.0%	-7.2%	
Power generation	-8.0%	-8.6%	-12.4%	-13.4%	
Percentage change in volume					
	Ntpa	tpa	Ntpa	tpa	Elasticity
Industry	2.3%	2.8%	3.6%	4.3%	-0.6
Power generation	4.0%	4.3%	6.2%	6.7%	-0.5
Present volumes	Ntpa	tpa	Ntpa	tpa	
Industry	25	25	25	25	
Power generation	50	50	50	50	
Change in volumes					
	Ntpa	tpa	Ntpa	tpa	
Industry	**0.6**	**0.7**	**0.9**	**1.1**	
Power generation	**2.0**	**2.2**	**3.1**	**3.4**	
New volumes					
	Ntpa	tpa	Ntpa	tpa	
Industry	25.6	25.7	25.9	26.1	
Power generation	52.0	52.2	53.1	53.4	

Table B7.16. More competition: border prices

Cost of producers				
	Ntpa	tpa	Ntpa	tpa
Industry	2.7	2.7	2.7	2.7
Power generation	2.7	2.7	2.7	2.7
Present rents				
	Ntpa	tpa	Ntpa	tpa
Industry	0.5	0.5	0.5	0.5
Power generation	1.2	1.2	1.2	1.2
Present % rent to producers				
	Ntpa	tpa	Ntpa	tpa
Industry	0.8	0.8	0.8	0.8
Power generation	0.8	0.8	0.8	0.8
Present border price				
	Ntpa	tpa	Ntpa	tpa
Industry	3.1	3.1	3.1	3.1
Power generation	3.7	3.7	3.7	3.7
New % rent to producers				
	Ntpa	tpa	Ntpa	tpa
Industry	0.7	0.7	0.6	0.6
Power generation	0.7	0.7	0.6	0.6
Efficiency under TPA and nTPA				
	Ntpa	tpa	Ntpa	tpa
Industry	0.0	0.1	0.0	0.1
Power generation	0.0	0.1	0.0	0.1
Rents under TPA and nTPA				
	Ntpa	tpa	Ntpa	tpa
Industry	0.5	0.6	0.5	0.6
Power generation	1.2	1.3	1.2	1.3
New border price				
	Ntpa	tpa	Ntpa	tpa
Industry	3.07	3.14	2.99	3.05
Power generation	3.57	3.64	3.38	3.44
Change in border price				
	Ntpa	tpa	Ntpa	tpa
Industry	(0.06)	0.02	(0.13)	(0.08)
Power generation	(0.14)	(0.07)	(0.33)	(0.27)

Table B7.17. More competition: consumer saving

	Scenario 1		Scenario 2	
Present expenditure				
Industry	88	88	88	88
Power generation	210	210	210	210
New exp at old volumes				
Industry	84	83	82	81
Power generation	193	192	184	182
Difference = US$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	134	163	209	253
Power generation	669	726	1040	1129

Table B7.18. More competition: change in producer revenue

Present revenue=US$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	3122	3122	3122	3122
Power generation	7410	7410	7410	7410
New revenue=US$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	3136	3225	3098	3179
Power generation	7415	7589	7178	7333
Change in revenue=US$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	15	103	-23	57
Power generation	5	179	-232	-77
	20	282	-255	-20

Table B7.19. Higher transmission company rents

	Power generation	Industry
Value of gas	4.20	3.50
Cost of producers	2.73	2.73
Cost of transmission	0.20	0.20
Rent in transmission	0.30	0.30
Other rent	0.97	0.27

Other assumptions

	Power generation	Industry
Elasticity	-0.5	-0.6
Volume affected (bcm pa)	50	25

Rent allocation	**Scenario 1**		**Scenario 2**	
Present situation	Barg/Pow	% of rent	Barg/Pow	% of rent
Producers	1	83%	1	83%
Transmission company	0.2	17%	0.2	17%
Consumers	0	0%	0	0%
TPA				
Producers	1	91%	1	71%
Transmission company	0	0%	0	0%
Consumers	0.1	9%	0.4	29%

Table B7.20. Higher transmission company rents: changes in producer revenues

			Scenario 1		Scenario 2	
Description	**Sector**	**Units**	**nTPA**	**TPA**	**nTPA**	**TPA**
Change in price	Industry	US$/MMBtu	(0.02)	(0.05)	(0.08)	(0.16)
	Power generation	US$/MMBtu	(0.09)	(0.12)	(0.28)	(0.36)
Change in volume	Industry	bcm pa	0.11	0.22	0.33	0.70
	Power generation	bcm pa	0.52	0.69	1.65	2.16
Total volume		bcm pa	0.63	0.91	1.98	2.86
Change in border price	Industry	US$/MMBtu	0.02	0.29	(0.03)	0.18
	Power generation	US$/MMBtu	0.07	0.35	(0.12)	0.10
Consumer saving (on present vol)		US$m pa	200.9	282.7	631.4	888.6
Total change in producer revenue		US$m pa	255.8	1,121.2	1.4	781.6

Table B7.21. Higher transmission company rents: elasticities effect on volume

	Scenario 1		Scenario 2		
% rent to consumers					
	Ntpa	tpa	Ntpa	tpa	
Industry	9.1%	9.1%	28.6%	28.6%	
Power generation	9.1%	9.1%	28.6%	28.6%	
Change in prices					
	Ntpa	tpa	Ntpa	tpa	
Industry	(0.02)	(0.05)	(0.08)	(0.16)	
Power generation	(0.09)	(0.12)	(0.28)	(0.36)	
Present final price	Ntpa	tpa	Ntpa	tpa	
Industry	3.5	3.5	3.5	3.5	
Power generation	4.2	4.2	4.2	4.2	
New final price	Ntpa	tpa	Ntpa	tpa	
Industry	3.48	3.45	3.42	3.34	
Power generation	4.11	4.08	3.92	3.84	
Percentage change in price					
	Ntpa	tpa	Ntpa	tpa	
Industry	-0.7%	-1.5%	-2.2%	-4.7%	
Power generation	-2.1%	-2.7%	-6.6%	-8.6%	
Percentage change in volume					
	Ntpa	tpa	Ntpa	tpa	Elasticity
Industry	0.4%	0.9%	1.3%	2.8%	-0.6
Power generation	1.0%	1.4%	3.3%	4.3%	-0.5
Present volumes	Ntpa	tpa	Ntpa	tpa	
Industry	25	25	25	25	
Power generation	50	50	50	50	
Change in volumes					
	Ntpa	tpa	Ntpa	tpa	
Industry	**0.1**	**0.2**	**0.3**	**0.7**	
Power generation	**0.5**	**0.7**	**1.6**	**2.2**	
New volumes					
	Ntpa	tpa	Ntpa	tpa	
Industry	25.1	25.2	25.3	25.7	
Power generation	50.5	50.7	51.6	52.2	

Table B7.22. Higher transmission company rents: border prices

Cost of producers				
	Ntpa	tpa	Ntpa	tpa
Industry	2.7	2.7	2.7	2.7
Power generation	2.7	2.7	2.7	2.7
Present rents				
	Ntpa	tpa	Ntpa	tpa
Industry	0.3	0.3	0.3	0.3
Power generation	1.0	1.0	1.0	1.0
Present % rent to producers				
	Ntpa	tpa	Ntpa	tpa
Industry	0.8	0.8	0.8	0.8
Power generation	0.8	0.8	0.8	0.8
Present border price				
	Ntpa	tpa	Ntpa	tpa
Industry	3.0	3.0	3.0	3.0
Power generation	3.5	3.5	3.5	3.5
New % rent to producers				
	Ntpa	tpa	Ntpa	tpa
Industry	0.9	0.9	0.7	0.7
Power generation	0.9	0.9	0.7	0.7
Efficiency under TPA and nTPA				
	Ntpa	tpa	Ntpa	tpa
Industry	0.0	0.3	0.0	0.3
Power generation	0.0	0.3	0.0	0.3
Rents under TPA and nTPA				
	Ntpa	tpa	Ntpa	tpa
Industry	0.3	0.6	0.3	0.6
Power generation	1.0	1.3	1.0	1.3
New border price				
	Ntpa	tpa	Ntpa	tpa
Industry	2.98	3.25	2.92	3.14
Power generation	3.61	3.88	3.42	3.64
Change in border price				
	Ntpa	tpa	Ntpa	tpa
Industry	0.02	0.29	(0.03)	0.18
Power generation	0.07	0.35	(0.12)	0.10

Table B7.23. Higher transmission company rents: consumer saving

	Scenario 1		Scenario 2	
Present expenditure				
Industry	88	88	88	88
Power generation	210	210	210	210
New exp at old volumes				
Industry	87	86	86	83
Power generation	206	204	196	192
Difference = $m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	25	52	77	163
Power generation	176	231	554	726

Table B7.24. Higher transmission company rents: change in producer revenues

Present revenue=$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	2955	2955	2955	2955
Power generation	7077	7077	7077	7077
New revenue=$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	2988	3277	2962	3225
Power generation	7299	7876	7072	7589
Change in revenue=$m pa				
	Ntpa	tpa	Ntpa	tpa
Industry	33	322	7	270
Power generation	223	799	-5	512
	256	1121	1	782

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Volume 10 Single energy market

EUROPE

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